FOSSIL ENERGY

NIPER/BDM-0086
CONF-940450
(DE95000116)

PROCEEDINGS

FIELD APPLICATION OF IN SITU COMBUSTION--PAST PERFORMANCE/FUTURE APPLICATION

SYMPOSIUM
April 21-22, 1994
Doubletree Hotel
Tulsa, Oklahoma

Compiled by
Partha Sarathi
David Olsen

January 1995

BDM-Oklahoma, Inc.
National Institute for Petroleum and Energy Research
Bartlesville, Oklahoma

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

NIPER/BDM-0086
CONF-940450
Distribution Category UC-122

PROCEEDINGS

Field Application of In Situ Combustion--Past Performance/Future Application

Symposium

April 21-22, 1994
Doubletree Hotel
Tulsa, Oklahoma

Compiled by
Partha Sarathi
David Olsen

February 1995

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Thomas B. Reid, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
BDM-Oklahoma, Inc.
National Institute for Petroleum and Energy Research
P.O. Box 2565
Bartlesville, OK 74005

TABLE OF CONTENTS

Page

Preface v
Introduction 1
Acknowledgments 2

ISC 1 *Redeeming Features of In Situ Combustion*, S. M. Farouq Ali, University of Alberta, Edmonton, Alberta, Canada 3

ISC 2 *Oxygen Enriched Fireflooding*, G. H. Shahani and H. H. Gunardson, Air Products and Chemicals, Inc., Allentown, Pennsylvania 9

ISC 3 *In Situ Combustion—From Pilot to Commercial Application*, A. Turta, Petroleum Recovery Institute, Calgary, Alberta, Canada 15

ISC 4 *DOE Cost-Shared In Situ Combustion Projects Revisited*, P. S. Sarathi and D. K. Olsen, BDM-Oklahoma, Bartlesville, Oklahoma 41

ISC 5 *In Situ Combustion Field Experiences in Venezuela*, M. Villalba, M. Estrada and J. Bolivar, INTEVEP, S.A., Caracas, Venezuela 65

ISC 6 *Romania—30 Years of Experience in In Situ Combustion*, V. Machedon, T. Popescu and R. Paduraru, Research and Design Institute for Oil and Gas, Cimpina, Romania 83

Technology Assessment—Discussion 97

ISC 7 *The Effect of Low-Temperature Oxidation on the Fuel and Produced Oil During In Situ Combustion*, D. D. Mamora of Texas A&M University, College Station, Texas, and W. E. Brigham of Stanford University, Stanford, California 101

ISC 8 *Comprehensive Kinetic Models for the Aquathermolysis of Heavy Oils*, J. D. M. Belgrave, R. G. Moore and M. G. Ursenbach, University of Calgary, Alberta, Canada 113

Laboratory Studies—Discussion 125

ISC 9 *An Evaluation of the Benefits of Combined Steam and Fireflooding as a Recovery Process for Heavy Oils*, R. G. Moore, C. J. Laureshen, J. D. M. Belgrave, M. G. Ursenbach, S. A. Mehta, and P. A. Gomez, University of Calgary, Calgary, Alberta, Canada, and K. N. Jha, Canmet, Ottawa, Canada 127

ISC 10 *The Use of Air Injection to Improve the Double Displacement Process*, M. R. Fassihi, Amoco Production Research, Tulsa, OK, and T. H. Gillham, Amoco Production Company, Houston, Texas 143

ISC 11 *Application of Horizontal Well Technology in a Mature Combustion EOR Project: Battrum Field, Saskatchewan, Canada*, F. N. Pebdani, B. G. Ames, R. E. Grams and R. W. Sanders, Mobil Oil Canada, Calgary, Alberta, Canada 159

TABLE OF CONTENTS—Continued

Page

ISC 12 *Shallow Oil Production Using Horizontal Wells with Enhanced Oil Recovery Techniques*, R. M. Satchwell, L. A. Johnson Jr., Western Research Institute, Laramie, Wyoming, and R. Trent, University of Alaska, Fairbanks, Alaska 169

ISC 13 *Naval Petroleum Reserve No. 3 (NPR-3), Teapot Dome Field, Wyoming: Case History of the In Situ Combustion Pilot Operation*, P. S. Sarathi and D. K. Olsen, BDM-Oklahoma, Bartlesville, Oklahoma; C. Ray Williams, U.S. DOE, Casper, Wyoming 179

ISC 14 *Enhanced Oil Recovery Using Hydrogen Peroxide Injection,* J. T. Moss, Jr. and J. T. Moss, Tejas Petroleum Engineers Inc., Dalas, Texas 203

Case Histories—Discussion 207

Summary of Panel Presentation and Discussion 211
- Summary of Presentation by W. C. Hardy 211
- Summary of Presentation by T. Buxton 212
- Summary of Presentation by G. Moore 213
- Summary of Presentation by J. Kirkpatrick 214
- Summary of Presentation by J. Moss 215

Panel Discussion 217

Koch Experience with Deep In Situ Combustion in Williston Basin—Keynote Address, R. Miller, Koch Exploration Company 229

Discussion 239

List of Symposium Attendees 246

PREFACE

For over four decades, in situ combustion has been used in the United States, Canada, Venezuela, and other parts of the world to improve oil recovery from existing fields. During this period, considerable effort has been expended by industry, academia, and service companies in understanding the mechanisms of in situ combustion in porous media and in improving and fine tuning field application techniques. Even though the process has been practiced for over 40 years, the technology is still evolving.

As part of its technology transfer mission, the U.S. Department of Energy periodically sponsors symposia on various aspects of oil recovery technologies. The basic objective of this DOE-sponsored in situ combustion symposium is to determine the state of the art in field application for oil recovery by providing a medium for information exchange among specialists in the technology. By encouraging the foremost experts on this subject matter to exchange their experiences and findings, their successes and failures, and their expectations of the projects, it was hoped that the technology could be further advanced and the risk of failures lowered.

The success of this symposium was due to a large number of people whose efforts we wish to acknowledge. In particular, we wish to recognize Dave Olsen and Partha Sarathi of BDM-Oklahoma for their dedication and enthusiasm in attending to the details and Dave Tiffin of Amoco Research for putting together the panel discussion group. We also thank the authors, panel participants, the keynote speaker and 78 symposium attendees for exchanging their experiences and voicing their views.

Thomas B. Reid, U.S. DOE

INTRODUCTION

By Partha S. Sarathi and David K. Olsen

The contents of this volume represent the collective presentations at a symposium, entitled "Field Application of In Situ Combustion—Past Performance/Future Application," which was held in Tulsa, Oklahoma, April 21–22, 1994. This symposium was sponsored by the U.S. Department of Energy (DOE) as part of its technology transfer mission and was organized by BDM-Oklahoma Inc., the management and operation contractor of DOE's National Institute for Petroleum and Energy Research (NIPER).

The symposium was organized into three technical sessions devoted to "Technology Assessment," "Laboratory Studies," and "Case Histories," and a panel session devoted to the assessment of the state-of-the-art of the technology. In addition to the panel and technical session, an invited keynote speaker assessed the technology from an operator's prospective on the evening of April 21, 1994. A total of 78 participants from seven countries attended the conference and the evening keynote address made the symposium an overwhelming success. A list of attendees is appended at the end of the proceedings.

A total of 14 technical papers were presented at the symposium and are included in these Conference Proceedings. These proceedings also included the keynote speaker's address and ensuing discussion along with the summary of panel presentations and discussion. For convenience, the proceedings are assembled into five parts, each containing related materials. The first part includes the six papers presented at the "Technology Assessment" session, followed by the papers discussion section. The second part includes all the papers presented at the "Laboratory Studies" session followed by the papers discussion section. The third part includes the five papers and the ensuing discussion that transpired during the "Case Histories" session. This section also includes a full text of one of the panel member's presentation (Paper ISC-14). The fourth part includes a summary of the panel presentation, and the discussion section. The final part includes the full text of they keynote speaker's address and the ensuing discussion. The papers are included in the order in which they were presented, and the discussion section includes selected questions posed by the audience to the speakers and their responses.

ACKNOWLEDGMENTS

We thank the Technical Program Committee for undertaking the difficult task of selecting abstracts of papers that reflect the current state of the in situ combustion technology, session chairmen for coordinating and conducting their section of the meeting, the authors for their willingness to share their experiences and findings, and the organizations that financed their work and permitted them to present their findings. The technical papers together with the associated discussion in these proceedings provide up-to-date information vital to an understanding of this technology.

We also wish to thank the panel members and registrants for making the panel session a success and for providing DOE with feedback on the current state of in situ combustion technology. We also wish to thank Mr. Ron Miller, General Manager, Koch Exploration Company for consenting to be the keynote speaker and making available to the public the details of Koch's in situ combustion projects. On behalf of the Conference Organizing Committee, the editors wish to thank Dr. David Tiffin for assembling and moderating the panel discussion, Annalea Kerr of BDM-Oklahoma for compiling this volume, and Bruce Ramzel of BDM-Oklahoma for video taping the meetings and transcribing the recordings.

This symposium was sponsored by the U.S. Department of Energy. On behalf of the participants, the editors wish to thank Thomas C. Wesson, Thomas B. Reid, and Herb Tiedemann of U.S. DOE, Bartlesville Project Office, for supporting this symposium.

DOE/NIPER

Redeeming Features of In Situ Combustion

by S. M. Farouq Ali, University of Alberta, Edmonton, Alberta, Canada

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

In situ combustion remains the most tantalizing enhanced oil recovery method. It has been tested extensively—in over 150 field tests—in both heavy and light oil reservoirs. What we have learned from this experience is that in situ combustion works under most conditions, but the nature of the problems is such that it is seldom profitable. Also, looking at many previous in situ combustion tests, steam injection, and even waterflooding, would have been a better choice. Yet in situ combustion has unique features not found in any other EOR method. These must be weighed against its shortcomings to evaluate a potential application.

This paper discusses the redeeming features of in situ combustion, in particular the reservoir conditions under which in situ combustion may be superior to other EOR methods are outlined. All variations of in situ combustion—forward, reverse, wet, dry—as well as combinations with other EOR methods are considered. The conclusions is that in situ combustion still has a place, and its future application would depend on research on certain crucial aspects of the process.

References and illustration at the end of paper.

INTRODUCTION

In situ combustion, also known less precisely as fireflooding, is a remarkable oil recovery method, with unique features possessed by no other EOR technique, as will be shown in this paper. Over the years, more than 150 in situ combustion field tests of various types and sizes have been reported. Some of them have been commercially successful, others technically successful (i.e., they produced oil) and many others "failed" (to be elaborated later). One fact that stands out in the case of failures—and even some of the successes— is that the process was applied in the wrong type of reservoir, or the operating conditions were inappropriate. In retrospect, one can make such judgments and perhaps identify the conditions under which in situ combustion is likely to be commercially successful. As far as that goes, right at the outset we can say that (i) in situ combustion is a very complex process and there is no general formula (screening criteria) to guarantee success; (ii) geology lies at the heart of the problem; (iii) it is more likely to succeed in light rather than heavy oils; and (iv) carefully planned laboratory work is absolutely necessary to determine if a project should be conducted at all.

The purpose of this paper is to outline the more attractive features of in situ combustion vis-a-vis other oil recovery methods. Along the way, the main problems with in situ combustion will be mentioned also. We shall see that in situ combustion has unique features not possessed by any other recovery method. The secret of success with in situ combustion lies in understanding its limitations and doing the homework (geology, laboratory work, experience).

THE RISE AND FALL OF IN SITU COMBUSTION

In situ combustion has a long history, which is not the purpose of this paper. A few highlights are worth recounting. It is said that the Russians started underground coal gasification (another form of in situ combustion), on Medeleev's suggestion in 1888. This led to in situ combustion in oil reservoirs. The author published one of the early surveys of in situ combustion,[1] followed by a longer listing of projects by Urdaneta et al.[2] A more recent survey was reported by Chu in 1980.[3] Other than that, Oil and Gas Journal publishes a listing of recent projects in their biennial EOR report.[4] The last such report (1992) listed 7 active combustion projects in the U.S. and three in Canada; at least two combustion projects are known to be in operation in Romania and India, respectively. The U.S. oil production by in situ combustion was 4,701 B/D in 1992, out of 460,691 B/D thermal production (Total EOR production was 760,907 B/D).[4] Over the last 15 years, the U.S. oil production by in situ combustion has been around 10,000 B/D, although the number of projects has varied greatly, as shown in Fig. 1. The increase in the projects around 1982 was because of the advent of oxygen-enriched combustion on one hand and the improved tax structure on the other. Notice also that the numbers do not imply continuation of the same projects—until a few years ago, new projects were started all the time and the old ones shut down. Recently, combustion projects have been started only abroad.

During 1950-65, much laboratory work was done, especially by Mobil and Gulf. Reverse combustion received a great deal of attention. Some of the finest analytical studies were published in this period, notable among them are the works by Poettmann and Benhand (1956), Ramey (1959), Bailey and Larken (1959), Thomas (1963) and Selig and Couch (1963). The last two are still the best methods for temperature calculation.

Water injection with air (Wet Combustion, COFCAW (Amoco's trademark)—Combination of Forward Combustion and Waterflood) was big news in 1967, when Shell, Exxon and Amoco published papers on the subject at the same time. This was indeed a major advance for in situ combustion. At the same time Amoco published several papers on failed pilots conducted under clearly inappropriate conditions (Craig).

During 1965-75, mature projects brought out many operational problems, and—mistakes. A notable example is the Gregoire Lake project in the Athabasca oil sands.[5] There was growing disenchantment with in situ combustion. With the looming oil crisis, and generous DOE support available, hastily designed combustion pilot tests (as well as other EOR tests) were started. Most of these died as the funds ran out. An example is the Paris Valley combustion project, which ended up as a mediocre cyclic steam operation.

Since 1975, interest in in situ combustion has been ebbing, first because of the lack of government support, second because of falling oil prices, and third because of the perception—and there is some truth in it—that in situ combustion is a process to be avoided, because of the problems associated with it. There was a brief period of renewed interest in combustion with the advent of oxygen-enriched combustion, as exemplified by the highly touted oxygen project of Greenwich Oil Company. In fact, oxygen-enriched combustion was considered back in 1965 for the Bradford field, following the extensive (unpublished) oxygen combustion work by the Bureau of Mines (Morgantown).

COMBUSTION PROCESSES

Many processes based upon crude oil oxidation in a porous medium have been proposed. It is not our intent to discuss the mechanics of these processes. Rather, the different processes are cited to clarify which ones are of interest.

Forward Combustion

Forward combustion is the process we shall be referring to throughout this paper. In this process, air is injected into a well, in which the formation is ignited, and subsequently the combustion zone is driven toward the producers, "burning" or displacing the fluids in its path, and often becoming more horizontal than vertical due to gravity segregation. Water may be injected with air (wet combustion), to recover the heat behind the front. Water injection has been truly a major advance in in situ combustion. Oxygen may be added to the air (oxygen-enriched combustion) to reduce the gas volume and augment the benefits of carbon dioxide generated by combustion. Oxygen has many disadvantages also, and oxygen-enriched combustion has not lived up to expectations after nearly 20 field tests. Pebdani[6] has noted the desirable aspects of this process. In the following discussion "air" will imply air or air with added oxygen. Oxygen-carbon dioxide[7] and air-steam[8] injection have also been proposed.

Reverse Combustion

Reverse combustion is another variation of combustion that received much attention during the late fifties, culminating in several field tests, highlighted by the early phases of Amoco's Gregoire Lake project in Athabasca oil sands, in Alberta, where several variations of reverse combustion were tested without success. The limitations of reverse combustion are best summarized by Weijdema and Tadema[9] in a one-page article entitled, "Reverse Combustion Seldom Feasible." In the following discussion, reverse combustion is not considered any further. Perhaps the only practical application of reverse combustion is in the underground gasification of coal.

UNIQUE FEATURES OF IN SITU COMBUSTION

In situ combustion has certain unique features. It has the highest thermal efficiency of all thermal methods for obvious reasons. It is the process of choice in a number of situations. We should note at the outset that the principal fluid involved in in situ combustion is air, which is very mobile and sensitive to formation heterogeneities, saturation and temperature gradients, and oil properties. Indeed, combustion has a better chance of success as a fieldwide process rather than as a process encompassing a few patterns, because in the former case all of the displaced fluids would be captured by the producing wells. Following are several examples of redeeming features of in situ combustion.

Thin Formations

In thin heavy oil formations (<30 ft), steam injection is inefficient because of the large heat loss. Large spacings must be used because of the small resource base. Under such circumstances, in situ combustion is the process of choice. It allows the use of large well spacings. The firefront (more accurately, combustion zone) comprises a thin ring, while the formation behind the front can be cooled down to the original temperature by water injection with air. The condition for the advance of the front is that the frontal temperature may not fall below the minimum combustion temperature as a result of heat loss and heat convection in the annular combustion zone, and that oxygen is available at the front to support combustion. In contrast, in steam injection, the advance of the steam front requires that a steam zone is present behind the front, with concomitant high heat loss to the adjacent formations. The result is that combustion can be employed in thin formation with large well spacings (e.g., 20 acres). Steam injection is limited (in most cases) to thick formations and much smaller well spacings. The combustion front slows down as the distance from the injection well increases, in view of the increasing frontal surface area and decreasing air flux. This can be remedied—in theory—by increasing air injection rate. This is almost never practical for many reasons. The important thing to recognize is that in a pattern drive, the air flux over the combustion surface is non-uniform, and may fall below the minimum air flux at places, leading to extinction there. The project design should allow for this, which can lead to considerable channeling problems.

Deep Formations

In situ combustion is well suited for deep reservoirs, containing light or moderately heavy oil, if other conditions favor combustion also. (This was not the case in the relatively deep, extremely light oil reservoirs, where wet combustion was tested (Craig).[10] Deep formations (over 5,000 ft) would tend to have relatively low permeabilities, high temperatures and consequently high in situ oil mobility. All of these conditions are favorable for combustion. Several deep combustion tests have been conducted, but have not been successful for other reasons, related to design or geology.

Bottom Water

An important application of in situ combustion is in reservoir containing a thick water leg. Almost no recovery method is likely to work under such conditions, but in situ combustion has a chance. The injected air is a non-wetting phase relative to water, and the chances are good that the air would create a partially desaturated zone below the oil-water contact. The injected air will channel through this zone, but the rest of the water leg will not cause air channeling. Note that if oxygen arrives at a producer, it may starts a "stationary" spontaneous combustion surface near the producer, leading to production stimulation as well as high temperature problems, including corrosion. This was noted by the author in a simulation study (1977),[11] and also speculated in the old S. Belridge project. Initially, a significant portion of the injected air would flow through the desaturated zone, but as the combustion front advances through the oil zone, an ever-increasing fraction of air flows through the oil zone, and in the end the process may still be viable. An example of such an operation that was successful was the Eyehill in situ combustion project in Saskatchewan. Other examples are the Caddo Pine Island[12] project and the Suffield project in Alberta. The latter provides an example of what to watch out for: if the water leg contains a significant oil saturation—high enough to provide the necessary fuel, a second combustion front may start in the water zone (as occurred in the Suffield project). If such a condition is recognized beforehand solutions can be worked out. a very unfavorable situation for combustion is the presence of a gas cap. In such a case the injected air would short-circuit intô the gas cap, and start a second, fast-moving front there. As this front advances, ever more air channels through the gas zone, starving the main front.

There is little question that in situ combustion is an attractive process when water zones, or even a water drive, is present. Steam has been rather problematic when bottom water is present, and may be made to work, as shown by the author in numerous papers, but the thickness, and horizontal and vertical permeabilities of the water zone are crucial. This is true for in situ combustion also, but the sensitivity is much less.

The case of very thin bottom water zones is of great interest for a number of recovery techniques, especially in reservoir containing a very viscous oil, even bitumen. Such zones serve as channels for transporting the mobilized heavy oil/bitumen in an external water phase. Many field examples of this type can be cited. (In some cases a path like that is created by fracturing or placing horizontal pipes, etc.). In situ combustion can be very effective if innovative use is made of such a path. A counter-example is the Gregoire Lake project,[5] where a thin, continuous bottom water zone was discovered only after the project had been shut down.[13]

Waterflooded Formations

Waterflooded reservoirs offer attractive opportunities for using in situ combustion. The problem with such reservoirs is the low oil saturation (which may be very high in the case of heavy oils: e.g., 70% to 80% in 2,000 cP oil reservoirs in Saskatchewan). Whichever recovery method is chosen, it must use an expensive fluid to displace a large volume of the mobile water and at the same time bank up the residual oil. As an example, in micellar flooding (suitable for light oils), over 0.2 pore volumes (PV) must be injected before any oil production starts. Air is an inexpensive fluid to do the job. Also, the combustion front is very effective in banking the residual oil. Several examples of this type can be found in the literature.

Steamflooded Formations

In fact, combustion can be a viable process even for steamflooded formations. The highly instrumented Charco Redondo project is an example of this type.[14] In this project, a low (about 10% PV) steamflood residual oil saturation was still high enough for fuel requirements for a subsequent combustion drive. Of course, in many successful steamfloods there may not be a high enough oil saturation to justify a combustion drive. This is not the case in cyclic steam stimulation operations in the oil sands of Alberta, and other very heavy oil formations. In Cold Lake cyclic operations, for example, the overall oil recovery is about 15%—often much less. Much brainstorming and field testing is underway to increase oil recovery. The situation is complicated by the presence of fractures (vertical, horizontal and everything in between) induced by the high injection pressures needed. In situ combustion offers a viable alternative, and has been tested successfully in several projects, notably the Marguerite Lake operation, the subject of several papers.[15]

Under these conditions, combustion occurs in high temperature channels, often the fracture (parting) paths, which serve as conduits for oil flow in a pressure cycling operation. Needless to say, such an operation is complex and needs careful planning and scheduling of air injection and blowdown cycles, but does produce extra oil.

High Temperature Requirements

In situ combustion has an important application in formations where high temperatures are needed. Steam is limited to about 600° F, whereas combustion zones can have temperatures of 1,000° to 1,200° F—in fact we have considerable control on them. Processing of oil shale is such an application. In situ retorting of oil shale, or combustion drives through fractures in oil shale or tar sand, are the only way to produce hydrocarbons from unconventional hydrocarbon resources, short of nuclear blasts (also proposed in the past). Underground coal gasification is similarly another application where high temperature in situ combustion is the only answer.

GENUINE PROBLEMS

While elevating the redeeming features of in situ combustion, we have to admit that the process has some genuine problems. So have all other oil recovery methods. Langley[16] has given a good discussion of the problems. We shall merely identify some of them. The principal problem is the lack of combustion front control, which is really relegated to inadequate understanding of the geology and petrophysics of the formation. High gas-oil ratios, and the concomitant high gas production rates cause a variety of mechanical problems, ranging from well equipment erosion, gas-locking of pumps, treating and separation, to pollution control. Producing wells may sand up because of increased water and gas production. Corrosion due to acids formed in the formation and high temperatures can take a heavy toll of well equipment. The acids and a host of low temperature oxidation products cause the formation of emulsions, the character of which may change from day to day. These chemicals may also cause precipitation of asphaltenes ("sludge") that may plug up the producers. Occasionally there may be a high temperature well, which may have to be cooled by water/corrosion inhibitor injection down the annulus, but must be kept producing, because often hot wells are good producers also. Not the least of the problems are compressor breakdowns that led to the termination of a field project in at least one case, because the combustion zone has traveled far enough because ignition could not be re-done, when the compressor was finally repaired. These and other problems make in situ combustion costly and sometimes people-intensive. Most of these problems can be solved, at least partially.

WHAT IS NEEDED?

Given that in situ combustion has so many desirable features, why is the process not being employed more widely and why is there so little research on it? The answer is simply the general disregard for basic (and even applied) research by major oil companies, exacerbated by low oil prices. In situ combustion holds great promise in many areas, such as Saskatchewan, where a viable oil recovery method beyond primary recovery and waterflooding (totaling about 10% of oil-in-place) does not exist. What is needed is a concerted research effort to examine the effect of heterogeneities (all types: geologic, mineralogical, saturation, temperature) on air/gas flow in the field and the laboratory in carefully designed in situ combustion projects, especially for the case of high water-air ratio, which under ideal conditions reduces to in situ steam generation. Scaled models should be designed and used for experiments. The most elaborate and the only ones known in their class were used by now non-existent Gulf Oil. New scaling criteria are available for designing such models (Islam and Farouq Ali).[17] At the same time, there should be a parallel effort to come up with improved numerical simulation methods. The present numerical simulations are woefully inadequate as predictive methods. Moving grids, and even superfine grids, are now feasible, using the present day computers. The basic data—reservoir, fluid, kinetics—should be extensive enough to justify such models. The value of laboratory experiments, including the simple fire tube tests, is indisputable in determining how a crude will "burn" in the field.

WHAT WE HAVE LEARNED

Looking at the vast experience with in situ, a few general comments can be made about in situ combustion and its attractive features and shortcomings. First, in situ combustion has many important advantages and applications that no other recovery method possesses, as noted previously. Second, most of the failures of in situ combustion have been due to application of the process to the wrong type of reservoir. This can be elaborated as follows: (i) inadequate understanding of geology and mineralogy of the formation; (ii) inadequate, or even non-existent laboratory work; (iii) field design that did not envision later problems, and changes in the operational strategy; and last but not least (iv) lack of experience.

REFERENCES

1. Farouq Ali, S. M.: "A Current Appraisal of In Situ Combustion Field Tests," *J. Pet. Tech.*, April 1972, pp. 477-485.
2. Mendoza, Luisa V., Lesbia Urdaneta and Franco D'Orazio: "Estimacion de los Parametros Basicos de la Combustion Mediante Correlaciones de Proyectos de Campo," VI Jornadas Tecnicas de Petroleo, Maracaibo, v. 2, Oct. 30-Nov. 2, 1979, pp. 342-351.
3. Chu, C.: "State-of-the-Art Review of Fireflood Field Projects," *J. Pet. Tech.*, January 1982, pp. 19-36.
4. Moritis, Guntis: "EOR Increases 24% Worldwide; Claims 10% of U.S. Production," *Oil & Gas J.*, Apr. 20, 1992, pp. 51-79.
5. Marchesin, L. A.: "Gregoire Lake Block 1 Pilot, 1976-1981," paper 82-33-62, presented at the 33rd Annual Tech. Meeting of Pet. Soc. of CIM, Calgary, June 6-9, 1982.
6. Pebdani, F. N.: "Status of Oxygen Fireflooding," SPE paper 18806, presented at the SPE California Regional Meeting, Bakersfield, Apr. 5-7, 1989.
7. Shu, W. R. and H. S. Lu: "Potential Benefit of CO_2 in Oxygen Combustion," *J. Pet. Tech.*, July 1984, pp. 1137-1138.
8. Lasaki, G. O., R. Martel and L. J. Fahy: "Design of a Field Experiment for Air-Steam Co-Injection for Oil Recovery in a Utah Tar Sand," SPE paper 11159, presented at the 57th Annual Fall Meeting of Soc. of Pet. Engrs., New Orleans, Sept. 26-29, 1982.
9. Dietz, D. N. and J. Weijdema: "Reverse Combustion Seldom Feasible," *Producers Monthly*, 1967, p. 10.
10. Craig, F. F., Jr., and D. R. Parrish: "A Multipilot Evaluation of the COFCAW Process," *J. Pet. Tech.*, June 1974, p 659.
11. Farouq Ali, S. M.: "Multiphase, Multi-dimensional Simulation of In Situ Combustion," SPE paper 6896, presented at the 52nd Annual Fall Meeting of Soc. of Pet. Engrs., Denver, Oct. 9-12, 1977.
12. Horne, J. S., I. Bousaid, T. L. Dore and L. B. Smith: "Initiation of and In Situ Combustion Project in a Thin Oil Column Underlain by Water," *J. Pet. Tech.*, October 1982, pp. 2233-2243.
13. Dr. T. J. Cyr, private communication (1988).
14. Widmyer, R. H., C. E. Howard, M. F. Fontaine and S. Haynes Jr.: "The Charco Redondo Thermal Recovery Pilot," *J. Pet. Tech.*, December 1977, pp. 1522-1532.
15. Hallam, R. J. and J. K. Donnelly: "Pressure-Up Blowdown Combustion," SPE paper 18071, presented at the 63rd Annual Fall Meeting of Soc. of Pet. Engrs., Houston, Oct. 2-5, 1988.
16. Langley, M. A.: "In Situ Combustion Experiences," presented at the Fifth Annual Advances in Petroleum Recovery and Upgrading Technology, Calgary, June 14-15, 1984.
17. Islam, M. R., and S. M. Farouq Ali: "New Scaling Criteria for In Situ Combustion Experiments," *J. Pet. Sc. & Engrg.*, v. 6, 1992, pp. 367-379.

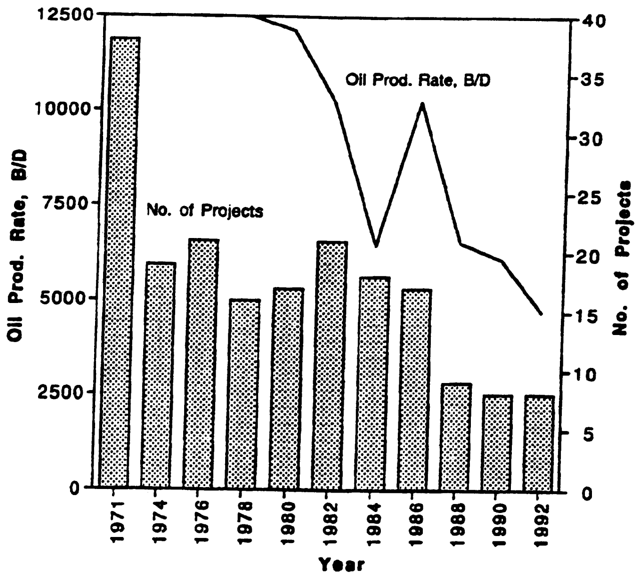


Fig. 1 In situ combustion projects carried out through the years and the respective oil production rates.

Oxygen Enriched Fireflooding

by G. H. Shahani and H. H. Gunardson, Air Products and Chemicals, Allentown, Pennsylvania

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

Both pure oxygen and enriched air have been considered in fireflooding for enhanced oil recovery. Laboratory and field testing have conclusively shown that oxygen is practical and cost effective for this application. For reservoirs that require a large volume of high pressure gas, oxygen is cheaper than air simply based on compression costs. Additional process benefits with oxygen include:

- Faster Oil Production
- Lower Injection Pressure
- Greater Well Spacing
- Increased Carbon Dioxide Partial Pressure
- Lower Gas-to-Oil Ratios
- Purer Produced Gas

These features provide a compelling case for oxygen, once the safety and materials compatibility issues are properly addressed.

INTRODUCTION

In fireflooding, like other oxidation and combustion processes, oxygen provides several distinct technical and economic advantages over air. By eliminating (or reducing) the nitrogen in combustion air, oxygen enrichment leads to: (1) lower quantity of combustion "air" and produced gas volumes; (2) higher oxygen partial pressure; and (3) higher combustion temperature. The higher combustion temperature and oxygen partial pressure symbiotically provide faster reaction kinetics with oxygen enrichment. These effects result in the following specific advantages of oxygen for fireflooding.

- Lower Injection Pressure
- Wider Well Spacing
- Increased Carbon Dioxide Partial Pressure

These features translate into the following benefits for the lease operator:

- Faster Oil Production
- Purer Produced Gases
- Lower Gas-to-Oil Ratios

These benefits have been demonstrated in the laboratory and successfully applied in field tests. Until now, oxygen enriched fireflooding has been considered a developmental technology. However, in the future, it will play a key role in enhanced oil recovery (EOR). The decision to develop a given reservoir with air or oxygen will depend primarily on economic, safety and materials compatibility considerations. This paper provides an overview of these important factors.

ECONOMICS OF OXYGEN VERSUS AIR

There are several techniques available for enhanced oil recovery. Steam flooding, nitrogen injection and pressurization, carbon dioxide injection and fireflooding have all been demonstrated for different applications. Fireflooding is applicable for certain extremely heavy crude oil reservoirs. Once fireflooding has been identified as the preferred technique there is the question of whether to use air or pure oxygen. A comprehensive economic analysis of air versus oxygen should include both the cost of delivering oxygen to the reservoir as well as its effect on the overall fireflood performance. Such an assessment should include the economic benefits of faster oil production, wider well spacings, lower gas-to-oil ratios and

References, tables and illustrations at end of paper.

purer produced gases. The analysis presented here addresses only the cost of delivering oxygen to a reservoir. As such, it is a conservative approach since it does not include the additional benefits of oxygen expected in the reservoir.

To inject oxygen into a well it is necessary to compress the gas to an elevated pressure. Compressing oxygen alone, without four times its volume due to the nitrogen in the air, takes a smaller compressor and less horsepower. This advantage in capital investment and operating cost for compression is offset by the cost of producing molecular oxygen in an air separation plant. The cost of producing oxygen decreases as the capacity of the air separation plant increases due to economies of scale. The larger the quantity of oxygen the lower is its unit cost. Therefore, the difference in cost between supplying oxygen or air at elevated pressure is a function of the quantity of gas supplied and the pressure at which it is delivered. This analysis for a range of quantities and delivery pressures is illustrated in Figure 1, "Air versus Oxygen Cost."

The quantity of contained oxygen[(1)] is shown on the x-axis. The y-axis shows the differential cost between compressing oxygen and air in cents per thousand standard cubic feet of contained oxygen. This differential cost takes into account the capital and operating cost of the compressor(s) as well as the cost of producing the specified quantity of oxygen at 99.5% purity over the economic life of the project. The economic life of the project is assumed to be fifteen years and both the power cost and the rate of return on investment are identical for both the air and oxygen systems. The delivery pressure is accounted for by the family of curves. The analysis is shown for three pressures: 1,000 psia, 1,500 psia and 3,000 psia. Discontinuities in the curves for 1,500 psia and 3,000 psia are a result of switching from a combination of reciprocating and centrifugal compressors at lower flow rates to reciprocating compressors at higher rates. This analysis was first published in 1983 following a successful field test of oxygen fireflooding at a site in Texas. This economic analysis of the cost of supplying oxygen versus air became known as 'Hvizondian Economics' (pronounced "Vizz-doan-i-an").

The conclusion from Figure 1, is that oxygen can be less expensive than air at high pressures and high flow rates. The savings gained from avoiding the compression of nitrogen more than offset the cost of oxygen. It may be pointed out that this analysis was completed over a decade ago. Since then, advances have been made to cryogenic air separation technology which has further reduced the cost of producing molecular oxygen. Incorporating these advances into the analysis will improve the economics of oxygen. While nitrogen may have an important part to play[(2)] in the overall fireflood performance, the "reservoir" effects are not included here.

New Developments

The economics of oxygen versus air presented above are based on cryogenic air separation. For almost a century, the cryogenic distillation of liquid air has been the dominant method for producing atmospheric gases. Cryogenic distillation is a mature technology that is particularly efficient at a large scale of operation. Recently, new developments in adsorption and membrane technology are steadily making inroads into the air separation market place.

Adsorption systems separate air a ambient temperature by passing air through a column of adsorbent. Adsorption systems that produce oxygen as the primary product, use an inorganic crystalline material known as a zeolite molecular sieve. This material selectively adsorbs nitrogen, and traces of water and carbon dioxide from air on its surface, allowing oxygen molecules to pass through the column. Adsorption continues until the adsorbent is fully saturated. The adsorber is then evacuated by a vacuum system, and waste gases are desorbed. This cycle is continuously repeated to produce 90+% pure oxygen at ~5 psig. For fireflooding and other combustion applications, low purity (~90%) oxygen is entirely satisfactory. However, the product gas must be subsequently compressed to the desired operating pressure. As noted earlier, compressing 90+% oxygen will be much cheaper than an equivalent volume of air.

Since their commercial introduction in the early 1970s, adsorption systems are becoming competitive at increasingly larger scales of operation. For example, vacuum swing adsorption plants for oxygen that were originally cost competitive at 20 - 30 T/d are currently competitive with cryogenics at up to 200 T/d. This improvement has been brought about by improved adsorbents and process cycle developments that have reduced both the capital and operating costs for adsorption systems. In the future, these systems can be expected to play a part in fireflooding projects—especially pilot tests and some smaller commercial operations.

SAFETY

The use of pure oxygen in a fireflood application raises concerns about safety. Generally, oxygen, especially at high pressure, is more hazardous than air. Many engineering materials that do not normally burn in air can sustain combustion in oxygen enriched atmospheres. It

(1) Contained oxygen means that the quantity of oxygen is the same in air and oxygen. In practical terms, 1 scf of air contains the same "contained oxygen" as 0.21 scf of pure oxygen.

(2) The absence of nitrogen reduces "gas" drive, which can retard oil production. However, with oxygen enrichment, a higher oxygen flux is possible. Also, the carbon dioxide partial pressure will be higher. These effects will jointly accelerate oil production and thereby provide faster cash flow.

may be noted that in fireflooding all three components of uncontrolled combustion—namely, oxidant, fuel and a potential source of ignition—are present. Consequently, special precautions must be taken in the selection of materials and operation of an oxygen based fireflood to ensure safe operation.

While the hazards associated with oxygen are important, they have been successfully addressed in a number of other industries. Tonnage quantities of oxygen at high pressure have been safely deployed in the steel, power and petrochemical industries over extended periods of time. For example, for over a decade, Air Products has supplied the Eastman Chemical Company in Kingsport, Tennessee up to 1,350 T/d of oxygen at 1,200 psi for coal gasification. Other applications include: the use of oxygen for the production of petrochemicals (such as ethylene oxide) and steel. Over the years, the experience gained from these applications, as well as specific research related to the use of oxygen in fireflooding have led to the following guidelines.

Metals Flammability

Many metals (including carbon steel) can burn in oxygen enriched air atmospheres. The flammability of metals is a complex phenomena which depends on the oxygen concentration, initial pressure, temperature, geometry, heat sink potential, and direction of burn.

Laboratory tests have shown that flame propagation in carbon steel is a strong function of the oxygen concentration and pressure. A series of experiments were carried out at Air Products' laboratories using specimens of carbon steel tubing. The tubing was selected so that it had a geometry similar to pipes used for injecting oxygen in a fireflood. In these experiments, the specimen was ignited at different pressures and initial oxygen concentrations to determine if the tube, once ignited, would sustain combustion. These results are summarized in Figure 2, which maps the flame propagation phenomena as a function of the pressure and initial oxygen concentration. It can be seen from this figure if the oxygen concentration is above a critical value for a certain pressure, the carbon steel tube, once ignited, would continue to burn. Below this critical oxygen concentration, the flame did not propagate in the carbon steel tube.

The hazards represented by this effect can be managed by incorporating a firebreak section in the oxygen injection well. The firebreak is a length of the casing and tubing that is made from metals that do not burn in oxygen. Nickel- and copper-based alloys are particularly good for this application. These materials are inherently non-sparking, which means that their melting point is below their ignition point. The use of a firebreak is cost effective since it does not entail extensive use of expensive alloys in large quantities.

Velocity Constraint

In order to further minimize the danger of metals flammability, it is important to ensure that the maximum velocity of oxygen in the piping system is always below a certain threshold value. High oxygen velocities can lead to particulate impacting metal surfaces which can cause a spark. The threshold value is a function of the prevailing temperature and pressure. Figure 3 shows the effect of internal pressure on the maximum velocity for straight runs of carbon steel pipeline. For bends and elbows, the maximum allowable velocity should be reduced by 50%. Normally, a pipeline which is properly sized for pressure drop will satisfy the above requirement. In sections where it is not practical to keep the oxygen velocity low enough, non-sparking copper- or nickel-based alloys should be used.

Materials Selection

The issue of metals flammability has already been discussed. In general, it is not necessary to use large amounts of exotic materials of construction. If the oxygen system is properly designed and operated, carbon steel is generally adequate. Some additional materials considerations are discussed below.

Welding should be done carefully in order to eliminate any sort of slag protrusion on the inside of the pipe. Furthermore, it is better to use new pipes and ancillary components as far as possible. New components are likely to be free of rust. If present, rust can flake off producing small particles which can cause sparks. Also, coatings of any sort on the pipe should be avoided. Coatings can be dangerous since many paints, lacquers and varnishes contain combustible compounds.

Cleaning

The cleaning of all oxygen pipeline components during pre-commissioning and turnarounds is as important as proper materials selection and equipment design. Without effective cleaning, properly selected materials of construction can be rendered ineffective. It is essential to remove all particulates and traces of oil and grease from pipes, fittings, valves, and instrumentation in oxygen service.

Even with new components, a carefully designed and well documented cleaning procedure is essential. Typically, an effective cleaning procedure includes: sand blasting, chemical cleaning with a suitable non-flammable solvent, followed by flushing with water and purging with oil-free nitrogen. Where possible, proper cleaning should be verified by visual inspection. However, this may not be possible in some situations. In such cases, the chemical composition of the cleaning fluid can be monitored on a periodic basis.

Produced Gases Flammability

At the production well, oil and gas are recovered from the reservoir. Ideally, in an oxygen fireflood that is operating properly, the produced gases contain over 90% carbon dioxide; with varying amounts of hydrogen, and C1 to C6 hydrocarbons; and traces of carbon monoxide, argon and oxygen. Most of the oxygen has been consumed in the oxidation of the coke to carbon dioxide and water. Normally, such a gas would be non-flammable because there is insufficient oxygen to sustain combustion (i.e., highly fuel rich). However, in some instances, oxygen can breakthrough the combustion front due to reservoir heterogeneity. If this happens, the produced gases become flammable; and only a spark is needed for ignition which can result in a disastrous explosion. With air, the potential for such a hazard is also present. However, the risk of explosion is not as great due to the presence of nitrogen in the air. In an air based fireflood, oxygen that breaks through to the production well will be accompanied with nitrogen.[3] The presence of nitrogen will mitigate the danger of an explosion.

Generally, the flammability of hydrocarbons in air (and to a lesser extent in oxygen) is well known in the literature. Also, the flammability of a hydrocarbon mixture can be calculated by the well known Le Chatelier's Rule. However, the flammability of hydrocarbon mixtures containing multiple fuels and inerts in oxygen enriched atomspheres at elevated temperature and pressure is not readily available. Recognizing this to be a critical success factor for oxygen fireflooding, Air Products developed a semi-empirical approach to satisfy this need. The methodology, known as PROMAP^{SM} is based on a calculation of the adiabatic flame temperature of various gaseous mixtures. Combined with the experience gained from laboratory testing and using the necessary safety margins, PROMAP^{SM} can predict whether a certain gaseous mixture is flammable.

In order to use PROMAP^{SM}, the gas composition along with the temperature and pressure has to be specified. Normally, gas samples are obtained at the well head. Since the gas composition at the well head is different from that at the bottom of the well due to vapor-liquid equilibrium, it is necessary to adjust the gas composition taking the appropriate pressure and temperature into account.

In addition to monitoring the gas composition it is a good idea to also track the temperature and pressure in the injection and production wells. The measurement of gas composition, pressure and temperature provides an early warning of a potential hazard so that the necessary corrective action can be taken. Depending on the conditions, it may be advisable to add either fuels, inerts or oxidizers to the production well in order to quickly move out of the flammable region.

CONCLUSIONS

Both pure oxygen and enriched air have been considered in fireflooding for enhanced oil recovery. Laboratory and field testing have conclusively shown that oxygen is practical and cost effective for this application. In general, oxygen is cheaper than air at high pressures and flow rates. Also, non-exotic materials of construction can be used in oxygen firefloods. Furthermore, flammability is predictable and controllable with oxygen. Air Products has the knowledge, experience and technology to assist lease operators with the development of this application.

REFERENCES (Uncited)

1. Hansel, J. G., M. A. Benning and J. M. Fernbacher: "Oxygen In-Situ Combustion for Oil Recovery: Combustion Tube Tests," *J. Pet. Tech.* (July 1984) pp. 1139-1144.
2. Shahani, G. H. and J. G. Hansel: "Oxygen Fireflooding: Combustion Tube Tests With Light, Medium and Heavy Crude Oils," *SPE Reservoir Engineering*, November 1987, pp. 583-589.
3. Hvizdos, L. J., G. W. Roberts and J. V. Howard: "Enhanced Oil Recovery Through Oxygen-Enriched In-Situ Combustion: Test Results From the Forest Hill Field in Texas," *J. Pet. Tech.*, June 1983, pp. 1061-1070.
4. Merington, L.: "Designing for safety in enhanced recovery oxygen fireflooding," *Oil and Gas Journal*, Oct. 31, 1983, pp. 124-128.
5. Persico, P.J., J. B. Wetherington and Hvizdos: "CO_2 Recovery From Oxygen Firefloods," *Energy Progress*, June 1983, pp. 91-96.
6. Hansel, J. G., J. W. Mitchell and H. C. Klotz: "Predicting and Controlling Flammability of Multiple Fuel and Multiple Inert Mixtures," presented at the 25th Annual Loss Prevention Symposium, Aug. 18-21, 1991.
7. Fernbacher, J. M. and J. G. Hansel: U.S. Patent 4,683,947, Aug. 4, 1987.
8. Roberts, G. W., J. G. Hansel and G. H. Shahani: U.S. Patent 4,690,215, Sept. 1, 1987.

[3] It may be noted that every mole of oxygen that breaks through will be accompanied with at least 3.76 moles of nitrogen. (The ratio of nitrogen to oxygen in air is 3.76.) Since some oxygen will be consumed in the combustion and low temperature oxidation, the nitrogen-to-oxygen ratio will, in all likelihood, be greater than 3.76.

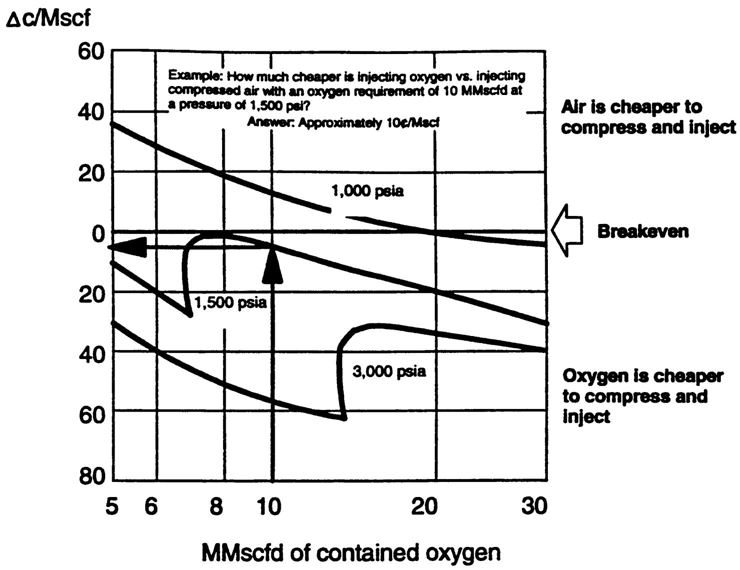


Fig. 1. Air versus oxygen cost.

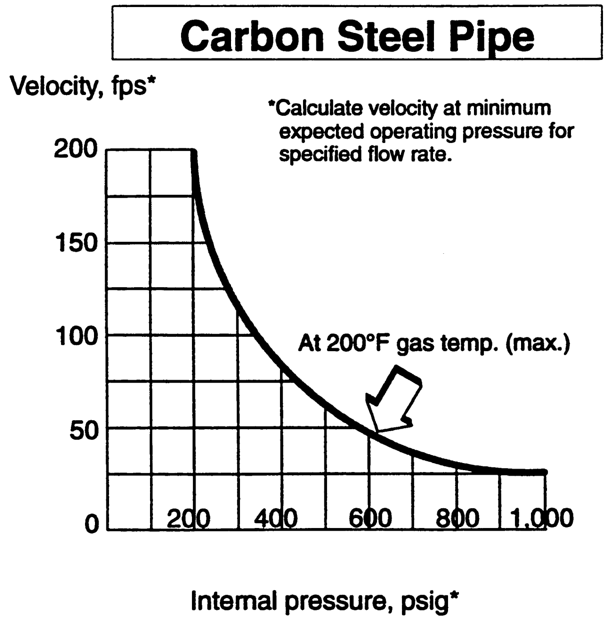


Fig. 3 Maximum allowable velocity.

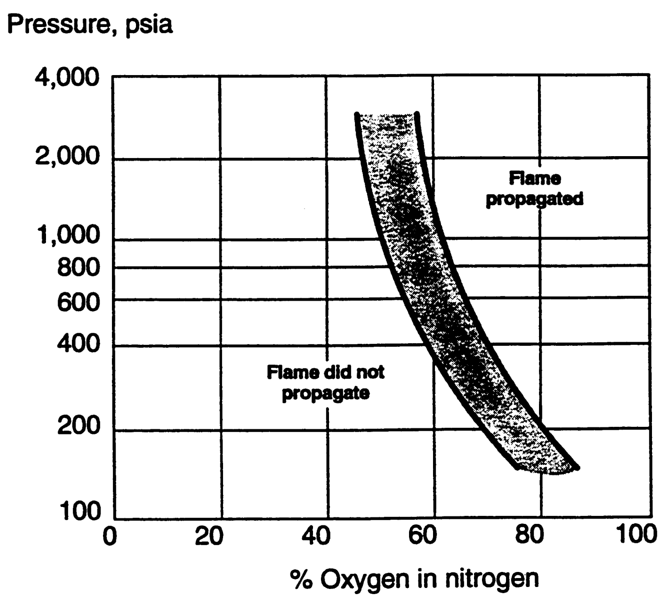


Fig. 2 Flame propagation of carbon steel.

In Situ Combustion—From Pilot to Commercial Application

by A. Turta, Petroleum Recovery Institute, Calgary, Alberta, Canada

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

In 1994, there are at least 14 active commercial in-situ combustion (ISC) projects worldwide. A review of these projects is carried out in order to emphasize the important factors which contributed to the success of the processes. The success of the developing an ISC pilot into a commercial ISC project is strongly connected with two factors: a) starting the operation from the uppermost part of the structure and extending the process downwards and b) application of the line drive well configuration instead of patterns, whenever is possible. An effective, peripheral line drive operation requires pool unitization.

The most challenging phase towards commercialization of an ISC project is the field pilot design, implementation and evaluation. This paper is focused on the advantages of locating ISC pilot at the upper zone of the reservoir, due to the need for a full scale integration of the pilot with the subsequent semi- and commercial development of the process.

The application of ISC to the light oil reservoirs is examined. In this case not only the successes, but also the less understood mechanisms and the field operational problems are discussed.

Finally, the horizontal wells as producers and/or injectors in the ISC process are analyzed. First, the results of horizontal wells employed as producers in two Canadian existing ISC processes are examined. Then, horizontal well assisted ISC is discussed, in connection with the advantages of the horizontal wells in substantially reducing the operational problems, which in most cases discouraged the operators to continue the expansion of the process.

References, tables and illustrations at end of paper.

INTRODUCTION

Patented in 1920 in USA, the first very short term field pilot (actually the first ignition operation) took place in the former Soviet Union in 1933-1934, while the true testing of an ISC process occurred in USA in 1950-1951.

So far, more than 160 ISC field pilot projects have been in operation. The process has been extensively studied both in laboratory and in field pilots. Although, there have been a great deal of work in this area, and presently there are more than 14 active commercial processes, worldwide, the general acceptance of the process is still debated. The causes for this situation are:

- The extremely high complexity of the process, coupled with a lot of difficulties in understanding how ISC works as a displacement process.

- Labour intensive character of the process.

- High difficulties in the rigorous evaluation of the pilot, due to the fact that the pilots were conducted in pattern or patterns which did not form a confined zone. This impeded the calculation of a reliable figure for the incremental oil recovery factor, although the value of air/oil ratio (AOR) was easily obtained.

- The lack of vision in the design of the ISC pilots for further development of the field process.

The goal of this paper is to clarify the role of a proper location of the pilot on the reservoir, emphasizing the advantages of locating the pilot at the uppermost zone of the reservoir. Doing so, we create the possibility of using the gravity to our best advantage in a further development of the process. In this context, also, the advantages of operating the process using the line drive well configuration are highlighted. Therefore, the paper tries to systematically illustrate the advantages of starting the ISC at the upper zone of the reservoir and, if possible, to operate it in a peripheral line drive system. Trials of this nature were studied for the steam drive, as well, using numerical simulation.[1] Actually, for the steam drive there is a total lack of consensus on how to operate the process, although the line drive (generally from upper zone of reservoir to water/oil contact) has been used to develop projects in dipping reservoirs.

COMMERCIAL IN-SITU COMBUSTION APPLICATION

Tables 1a and 1b present the main information on commercial ISC processes. The oldest process is West Newport, USA with 33 years, while the youngest is Karajanbas, in West Kazakhstan near Caspic See, with 11 years. Fourteen out of these 19 projects are currently active. As of April 1992, according to OGJ oil report, the incremental daily oil production due to ISC was approximately 4,700 BOPD (from 8 processes) in USA,[2,3] while the same figures were 8,000 BOPD (from 10 processes) for former Soviet Union, 7300 BOPD (from 3 processes) for Canada[2] and 12,000 BOPD (from 5 processes) for Romania.[4] Therefore, the 1992 world incremental daily oil production due to ISC was about 32,000 BOPD (from 26 reported processes). The number of processes reported -26 - includes not only commercial but also some semi-industrial processes, so that the oil production figure doesn't coincide with the table 1a and 1b reported oil production. The statistics presented in tables 1a and 1b are based, also, on the data published in the papers[5,6] and other sources specified at the end of tables.

For the purposes of this paper, commercial ISC project will be defined as a project having at least 2 air injectors, being in progress for over 8 years, and the area processed by ISC being a large portion of the reservoir. Also, a minimum daily oil production of 400 bbl/day for most of the time was required. Given these criteria, processes like Miga, Venezuela, Fosterton, Eyehill and Countess B., Canada, Posesti, Ochiuri, and Babeni, Romania and others were not included. On the other hand, Brea Olinda project was included because practically the whole block was processed by ISC although only 2 injectors were employed; high values for air injection rates and cumulative air injected were recorded.

Limited information is available on the commercial ISC projects. As a matter of fact, for 5 processes the information is limited to some fragmented news about those processes and there are no case history papers. Although not published at all, an important commercial in-situ combustion process had been in progress for a long period of time in Albania, in the Drisa reservoir. The process involved more than 40 air injection wells. Actually, there is a chance that there are other ISC commercial processes which have been operated quietly for years.

For the commercial processes listed in this work the viscosity is in the range 5-8,000 cP. And, actually, the conclusions of this paper in its entirety, refer to this range. What is stated here applies to the ISC applications in case of in-situ recovery for oils with natural mobility at reservoir conditions.

The process can be applied in a wide range of depths, from shallow to very deep reservoirs (11,000 ft), and a wide range of permeability, the lowest being 20 mD.

Out of the listed processes, 9 were started from the uppermost part of the structure, and at least 7 have been operated using the line drive well configuration.

The most important parameters, indicative of economics efficiency, are AOR and injection pressure. For the same value of AOR, less injection pressure means better economics. The AOR is in the range of 6,000 to 25,000 scf/bbl for injection pressures of 200 to 3,700 psi.

Three projects, actually, are ISC processes successfully applied in deep light oil reservoirs where steam drive can not work. The main features of most commercial processes listed in tables 1a and 1b are given in table 3.

WAYS TO APPLY COMMERCIAL ISC PROCESSES. STARTING FROM UPPER OR LOWER PART OF THE RESERVOIR LINE DRIVE WELL CONFIGURATIONS OR WELL PATTERNS APPLICATION?

Different types of wells flooding networks may be used for the ISC applications.

An idealized reservoir with the lower zone (W/O contact) and upper zone distinctively marked, are shown in figure 1.

There are two way of applying ISC; in well patterns and line drive well configuration. The first system could be applied as contiguous patterns or isolated patterns. The location of patterns may be upstructure or downstructure. So far all three configurations were tried, but most of applications used contiguous patterns and peripheral line drive configurations. The isolated patterns were only used in the West Newport commercial process.

The options for the expansion from the pilot to a field scale commercial application are displayed in figure 2. As shown, the line drive is possible to be applied only starting from the upper part of the reservoir. For this reason it is extremely important to place the pilot upstructure. In this way, after the test is finished, one can have both options of developing to commercial phase, that is, either line drive or patterns.

The Peripheral Line Drive Well Configuration

A schematic of line drive well configuration is shown in figure 3. Essentially, the commercial line drive operation means that the first row of wells at the uppermost part of the structure is to be used as air (air/water) injection wells (combustion wells) while producing the displaced oil by the nearby 2-3 production well rows, which are isobathically below the isobath of the injector row. Once the closest production row is intercepted by the combustion front this row is converted into air (air/water) injection, while behind, the former air injection row is used for water injection or simply shut off. Therefore, except the first uppermost well row, all other wells are utilized first as producers and afterwards as combustion wells. One more exception is the last lowest row on the structure which is used only as production well row. In this system, a secondary air gas-cap is formed and this is bigger and bigger as the ISC front is advancing towards the water-oil contact. A schematic of a real line drive application, that of the Suplacu de Barcau, after 20 years of commercial operation is shown in figure 4. As a rule, the front has been propagated as much as possible parallel to the isobaths. So, the front was moved towards the oil-water contact.

To decide between line drive and patterns application is one of the most important responsibilities of the designer. As was shown previously, and is graphically represented in the flowchart of figure 2, when starting from the upper part of the reservoir one can develop the commercial ISC process both using line drive and patterns, while when beginning from the lower part the use of only patterns system can be contemplated. All the design parameters shown at the bottom of the diagram will depend of the above mentioned choice. For the line drive, the rate of oil recovery is limited by the length of isobath. Therefore, one can not use any oil production rate, being limited on the higher side of the air rate values; there are some time constraints as far as the total life of exploitation is concerned.

ISC, in principle, is a gas injection which has additional beneficial effects associated with the propagation of the heat wave generated by the ISC front. Like a conventional peripheral gas displacement, it is just normal to start the process upstructure. Actually, only the existence of a primary extended gas cap should prevent locating the pilot upstructure.

Irrespective of the system one chooses for further development—line drive or patterns—**it is very important that the pilot be located at the uppermost part of the reservoir.** Another reason behind this statement is that usually when the pilot is located upstructure there is a good possibility of more rigorous evaluation of oil recovery. There is a rigorous way to delineate a volume of reservoir located at the upper part of the reservoir and which is under the influence of the combustion and for which both AOR and incremental oil recovery factor can be reliably calculated at any time. The reliable calculation of incremental oil needed for the AOR calculation and of incremental oil needed for the incremental oil recovery factor by ISC will be addressed later both for upper location and for a non upper location of the pilot.

Another positive side of locating the pattern at the upper part of the structure is that in case the testis inconclusive or deemed uneconomical—although the burning was OK or almost OK—the operator can just stop the air (air/water) injection and walk away. Oil resaturation of the burning zone is not going to take place or it should be minimal. If the pilot is not located at the upper part stopping air and walking away is not a good practice because the burned zone may be unintentionally transformed into a cracking reactor with the formation of large quantity of coke. For this reason, at the abandonment of the ISC pilot it is recommended to inject a volume of water equal to at least 0.8 burned pore volume for the dry combustion and less than that amount for wet combustion. At the termination of the ISC pilot another practice which is even more harmful than the previous one is to put the injector back into production. This practice originates from the corespondent practices in other EOR processes (steam drive, water flooding etc.). In the case of ISC the things are more complicated, because unknowingly the operator set up an underground coking installation, producing important amounts of coke. Obviously, it can be argued that the technique of cyclic combustion, which is similar to that of cyclic steam injection, does exactly this thing. In fact, it is not exactly the same because the burned zone is intentionally propagated only a few meters around the combustion well, in a few months time interval. Detailed studies of over 30 cyclic combustion operations[18] convincingly showed that after more than 6-7 months of ISC front propagation, even from the point of view of oil production the technique of returning into production of the combustion well doesn't make too much sense. But even if good oil production is obtained is still recommended to think twice before putting the well into production. Of course, if after years of combustion one converts into production well the combustion well, for dry combustion mainly, that operator is looking for troubles; visibly, lots of sand influx with a lot of workover for only a little of oil, and, invisibly, the formation of a large underground coking reactor.

In other modified ISC processes[19,20] in which the flowing of oil through the burned zone occurs intentionally, a shown, the line drive is possible to be applied only starting from the upper part of the reservoir. For this reason it is extremely important to place the pilot upstructure. In this way, after the test is finished, one can have both options of developing to commercial phase, that is, either line drive or patterns.

The Peripheral Line Drive Well Configuration

A schematic of line drive well configuration is shown in figure 3. Essentially, the commercial line drive operation means that the first row of wells at the uppermost part of the structure is to be used as air (air/water) injection wells (combustion wells) while producing the displaced oil by the nearby 2-3 production well rows, which are isobathically below the isobath of the injector row. Once the closest production row is intercepted by the combustion front this row is converted into air (air/water) injection, while behind, the former air injection row is used for water injection or simply shut off. Therefore, except the first uppermost well row, all other wells are utilized first as producers and afterwards as combustion wells. One more exception is the last lowest row on the structure which is used only as production well row. In this system, a secondary air gas-cap is formed and this is bigger and bigger as the ISC front is advancing towards the water-oil contact. A schematic of a real line drive application, that of the Suplacu de Barcau, after 20 years of commercial operation is shown in figure 4. As a rule, the front has been propagated as much as possible parallel to the isobaths. So, the front was moved towards the oil-water contact.

To decide between line drive and patterns application is one of the most important responsibilities of the designer. As was shown previously, and is graphically represented in the flowchart of figure 2, when starting from the upper part of the reservoir one can develop the commercial ISC process both using line drive and patterns, while when beginning from the lower part the use of only patterns system can be contemplated. All the design parameters shown at the bottom of the diagram will depend of the above mentioned choice. For the line drive, the rate of oil recovery is limited by the length of isobath. Therefore, one can not use any oil production rate, being limited on the higher side of the air rate values; there are some time constraints as far as the total life of exploitation is concerned.

ISC, in principle, is a gas injection which has additional beneficial effects associated with the propagation of the heat wave generated by the ISC front. Like a conventional peripheral gas displacement, it is just normal to start the process upstructure. Actually, only the existence of a primary extended gas cap should prevent locating the pilot upstructure.

Irrespective of the system one chooses for further development—line drive or patterns—**it is very important that the pilot be located at the uppermost part of the reservoir.** Another reason behind this statement is that usually when the pilot is located upstructure there is a good possibility of more rigorous evaluation of oil recovery. There is a rigorous way to delineate a volume of reservoir located at the upper part of the reservoir and which is under the influence of the combustion and for which both AOR and incremental oil recovery factor can be reliably calculated at any time. The reliable calculation of incremental oil needed for the AOR calculation and of incremental oil needed for the incremental oil recovery factor by ISC will be addressed later both for upper location and for a non upper location of the pilot.

Another positive side of locating the pattern at the upper part of the structure is that in case the testis inconclusive or deemed uneconomical—although the burning was OK or almost OK—the operator can just stop the air (air/water) injection and walk away. Oil resaturation of the burning zone is not going to take place or it should be minimal. If the pilot is not located at the upper part stopping air and walking away is not a good practice because the burned zone may be unintentionally transformed into a cracking reactor with the formation of large quantity of coke. For this reason, at the abandonment of the ISC pilot it is recommended to inject a volume of water equal to at least 0.8 burned pore volume for the dry combustion and less than that amount for wet combustion. At the termination of the ISC pilot another practice which is even more harmful than the previous one is to put the injector back into production. This practice originates from the corespondent practices in other EOR processes (steam drive, water flooding etc.). In the case of ISC the things are more complicated, because unknowingly the operator set up an underground coking installation, producing important amounts of coke. Obviously, it can be argued that the technique of cyclic combustion, which is similar to that of cyclic steam injection, does exactly this thing. In fact, it is not exactly the same because the burned zone is intentionally propagated only a few meters around the combustion well, in a few months time interval. Detailed studies of over 30 cyclic combustion operations[18] convincingly showed that after more than 6-7 months of ISC front propagation, even from the point of view of oil production the technique of returning into production of the combustion well doesn't make too much sense. But even if good oil production is obtained is still recommended to think twice before putting the well into production. Of course, if after years of combustion one converts into production well the combustion well, for dry combustion mainly, that operator is looking for troubles; visibly, lots of sand influx with a lot of workover for only a little of oil, and, invisibly, the formation of a large underground coking reactor.

In other modified ISC processes[19,20] in which the flowing of oil through the burned zone occurs intentionally, a serious concern still should be of how to control the coke deposition in the burned zone, given the fact that there are no easy ways of controlling this; the exact geometric configuration of the burned volume is never known.

Line Drive Well Configuration Versus Well Pattern Configuration

The main advantages of the line drive over the well pattern configuration are:

- The line drive fully takes advantage of the gravity (higher oil recovery) because the oil displacement is more gravity stable.
- Full control regarding the avoiding of oil resaturation of the burned area, which can lead to an important increase of air requirement and decrease of efficiency of process.
- Easier evaluation of the process (mainly ultimate oil recovery) in case that the semi-industrial process has to decide the final economical indicators, and for the early life of the commercial operation.

Easier operation due to the following reasons:

- Each producer is intercepted by the ISC front only once. For the patterns system as many as 4 ISC fronts may intercept the producer, and the risks of damaging the wells are higher.
- The area of combustion gas distribution is much smaller when using line drive system (less gas analyses for the same oil production).
- Less artificial ignition operations with the line drive system, given the possibility just to make an air transfer to the new row of recently intercepted (by the ISC front) producer row.
- Easier and more reliable tracking of ISC front. After the first row of producers is intercepted by the front, the tracking of the front position is a lot easier, just by assessing the interception for each producers.

On the other hand, the main advantages of the pattern configuration over the line drive system is the use of different completions for injectors and producers (including perforating different interval in injectors and producers), and the liberty to select any rate of oil production, by operating simultaneously as many patterns as the operator wants. The first advantage is important mainly for the ISC application in a multilayer oil formation, when the separation between layers is not very well defined. When several companies are operating on the same reservoir, the application of the line drive requires the unitization of the pool, while the patterns system doesn't.

Some operators report increase of oil production when reducing the air rates or even stopping the air injection in the patterns. Sometimes this is presented as an advantage of the patterns system, which seems to be incorrect. In reality, the advantages of this increase in oil production may be very misleading as in the air injection stoppage period, the oil outside the swept zone is flowing into the high temperature burned zone, and the cracking of the oil produces huge amounts of coke. This phenomenon is even more harmful as compared with the pushing of the oil into the gas cap during conventional waterflood. The increase of air requirement and of the air-oil ratio are the direct consequences if a continuation of the process is desired. Otherwise big volumes of coked rock will remain in the reservoir. Evidence of this phenomenon was revealed by the coring wells, in the burned area of the first ISC pilot at Suplacu de Barcau.[21] As shown in figure 5, the coke deposits as high as 170 Kg/m^3 rock were measured along a pay thickness portion of 3.5 m at the boundary between the burned and unburned zones, as compared with 35 Kg/m^3 rock, the normal, coke deposit for this reservoir. These very high deposits were caused by frequent fluctuations in the injection pressure and stoppages of air injection which were inherent for the very beginning of the process, when the running of the air compressors was not a routine operation for the field personnel.

DESIGN AND EVALUATION OF AN ISC PILOT PROJECT

From Laboratory Tests to Field Scale Application—The Integrated Approach

In order to apply the ISC commercially one needs to conduct the following four phases: laboratory tests; field pilot test design; evaluation of the field pilot test; and expansion to field scale operation.

The laboratory tests will give information about the chemical reactivity of oil-rock couple, some kinetic data to be used in mathematical simulation and a base figure concerning the amount of fuel deposited and/or burned during combustion. This last figure cannot be obtained from pilot data, whatever detailed analyses and measurements are carried out in the field. Also, from the pilot, there is no reliable means of determining or checking the value of air requirement, which, also, has to be determined in laboratory. Is the field pilot test a necessity? Usually it is. More precisely, to carry out a pilot is a rule, and the skipping of the pilot is rather an exception. The field pilot test will show if the ISC has the self-supporting capacity, if it has the ability to give incremental oil and what operational difficulties are to be expected in a future full scale process.

So far, there have been no operational guidelines regarding the design and evaluation of the pilot or semi-industrial ISC processes. Now, the decades of ISC experiences allows us to formulate some simple operational guides which, at least, will permit us to anticipate some problems to be encountered depending of the way the pilot is located on the reservoir.

Out of the above mentioned phases, the most challenging and usually the stumbling block, is the evaluation of the ISC pilot. The evaluation is totally dependent of the way the experimental pattern is located on the structure.

The most important performance indices for the evaluation of an ISC process are injected air/incremental oil produced ratio, AOR, and the incremental oil recovery factor(incremental oil/OOIP)—IORF. The value of incremental oil is not necessarily the same figure for AOR and IORF, because for the patterns system, the offset wells show an enhancement in oil rates, as well. The incremental oil from the offset wells are taken in consideration only when calculating AOR. Therefore, usually, the incremental oil for the calculation of AOR is associated with a larger area than in the case of determining the incremental oil for the calculation of IORF. The calculations of these performance indices are made easier if the pattern is located upstructure. This recommendation is valid also for the cases where the dip is very small, even 2 - 3 degrees.

Given the very high value of front-end investment (mainly for compressors) a gradual development of ISC is recommended. The experience showed that it is a good idea to expand the pilot into a semi-industrial process.

Field Examples of Pilot Location

One of the most important difficulties associated with an ISC pilot is to establish the ultimate oil recovery factor possibly to be obtained by ISC. Locating the pilot updip can substantially reduce the frustrations associated with the assessment of this parameter.

In the following two field cases will be presented, illustrating the main aspects associated with these two approaches of locating the pilot.

Suplacu de Barcau Field

The most in-depth exploration of the effect of location of pilot on the reservoir was performed at the Suplacu de Barcau Field.[21]

The Suplacu de Barcau reservoir is a monocline. There is a major fault limiting the reservoir to the South, while to the North the oil reservoir borders upon an aquifer. Both the depth and the thickness increases from South to North. The reservoir properties are given in table 3.

To select the best location for starting ISC process three different experimental patterns were located: up-, middle- an down- structure, as shown in figure 6. These patterns were operated more than 5 years.[16] The upper pilot gave the best result in terms of AOR value. Thus, for the ones in the middle and in the lower part of the reservoir, the AOR was between 16,800-22,800 scf/bbl, unfavorable values as compared to the value of 8,400 scf/bbl for the pattern at the upper part of the field. These unfavorable AOR were due to the intensive channeling of gases towards the upper part of the field, without causing increases in the oil rate for the wells towards the ISC front was channeling. However, after 5 years of operation, even for the pattern located at the upper part, the incremental oil recovery factor was not yet possible to be calculated and the decision to go ahead with a semi-industrial phase was made.

During the ISC semi-industrial phase, after three years of operation, a procedure to calculate the incremental oil production was established [20]. This procedure is exemplified in figure 7, where the delimitation of the zone considered for the calculation of incremental oil recovery factor is shown. The procedure consists of the following: The most downstructure producer which recovered combustion gas was picked up and through the base of its perforations an horizontal plane was drawn, "the contact surface" between ISC affected and nonaffected zone. For this region both current incremental oil recovery factor and the ultimate oil recovery factor were calculated. For the inside producers (producers on the affected area) the entire oil production was taken into consideration, while for all the producers located on the contact surface only half of the oil production was considered. The sum of these two figures divided by the OOIP in the "reservoir delimited by the contact surface" gave the current oil recovery factor. Because the majority of wells were still producing oil, production extrapolation allowed the calculation of the ultimate oil recovery. This calculation was made every 2-3 years. A conservative oil recovery factor of 35% was obtained for the first calculation, and this figure increased in the subsequent years. Finally, when a substantial zone was completely burned out, for that zone, the ultimate oil recovery factor was calculated directly; A value of 54% was the result of direct calculation for the above mentioned zone.

It has to be mentioned that this way of calculation would not have been possible if the semi-industrial ISC zone had not been located upstructure.

An important point to be made here is that applying this procedure the value for the incremental oil is the same figure both for AOR calculations and for oil recovery factor calculations.

West Balaria Field

Now, the case when the pilot is not located updip, will be considered. At West Balaria, the pilot patterns were located somewhere in the middle of the block.[22] However, to have a possibility to calculate the oil recovery factor the 4 inverted 5-spot patterns were arranged such that they formed a confined pattern (inside the 4 injectors) with only one producer for this pattern. The confined direct 5-spot pattern formed by 4 contiguous inverted 5-spot patterns, for a reliable calculation of oil recovery by ISC is shown in figure 8. The incremental recovery factor is obtained straightforward by dividing the incremental accumulated oil production of the central production well to the OOIP existent in the confined pattern. The procedure is risky because the only producer could be damaged during the ISC process. Actually, later on, two more contiguous patterns were added and in this way the second confined pattern was formed.

On the other hand, the incremental oil used in the AOR calculation is determined for an enlarged zone (as shown in fig. 8), larger than the pattern area, as many of the offset wells experienced increased oil rates. This situation happened in many pilots worldwide, such as Golden Lake Sparky and Aberfeldy,[23,24] to cite just two pilots. There are means of calculating this parameter, based on extra oil recovered (over the primary performance curve), for the enlarged zone. However, this incremental oil figure can not be used for oil recovery calculations, because there is no way of determining the OOIP to be used, for this enlarged area. Therefore, for contiguous patterns not located upstructure, the figures for incremental oil to be used in AOR and incremental oil to be used in oil recovery calculations were different and this is the general case with pattern applications. Allotment of fireflood related oil production to a particular injector (pattern) is practically impossible, although it is sometimes claimed.

The time necessary for a reliable evaluation of the ISC pilot and expansion to commercial scale.

In essence, the elapsed period between the initiation of the ISC pilot and the field full scale ISC is related to the pattern area, the air injection rates used during the pilot, and the location of pilot.

The elapsed period between the initiation of the ISC pilot and the field full scale ISC initiation for five commercial processes is displayed in table 4. It is to be mentioned that the area of experimental patterns was small 1 - 3 acres. Even for these small patterns 6 - 8 years elapsed between the ignition of the first pattern and the initiation of the full scale ISC operations on those reservoirs. In most cases, the real duration was 1.5 - 2 times higher than the initially predicted value.

At Videle East the pattern area was extremely high, 25 acres.[30] However, the elapsed time was only 7 years because the Balaria experience was very helpful. As shown in figure 9, Balaria and Videle are adjacent reservoirs with similar reservoir properties. Some experienced people already were formed while operating the Balaria ISC pilot and though some of the Balaria operational problems, emulsions, coke blocking of perforations, etc. appeared again, the decision to expand to the commercial phase was taken even before the ISC pilot was over in Videle East. Presently, there are 4 commercial ISC processes in the Videle-Balaria zone. The last one, Balaria East, was started directly as a commercial process, given the experience acquired in the other 3 nearby commercial processes. Later on, the decision to go directly to the full scale proved to be right.[4]

Of course, the most uninspired scheme is to have large pattern areas and to operate with low air fluxes. In this case the low temperature oxidations (LTO) may convert the ISC process into a process where, in reality, there will no longer be a combustion front (a high temperature wave) and the oxygen is consumed in LTO reactions spread all over the place, increasing the viscosity of oil, instead of decreasing it. While the LTO may take place even in the high air injection rate processes this is mainly a feature of low air injection rate processes. Usually, there is a reluctance in reporting such cases. However, reporting cases of this nature is very important for the progress of knowledge in the area of ISC application. In the open literature only the case of Kinsella Field[25] and Demjien-East[26] ISC pilots were explicitly reported. For Kinsella, the values of apparent H/C ratios were higher than 5-6. These high steady values for apparent H/C ratios, corroborated with other data showed the predominance of LTO reactions. At Demjien-East, air rates of only 6,000-8,000 sm^3/d, plunged the process in the LTO regime, with combustion gases having 2-4% O_2 and 2-4% CO_2.

For Dofteana Oligocene and Solont Stanesti processes,[4,15] conducted in microfractured sandstones, it is believed that the switching to the LTO took place due to the very high heat losses around the channels through which ISC front was propagated. For both cases the air injection rate of 10,000-12,000 sm^3/m^3 was too low for a pay thickness of 50-60 m; the very low injectivity contributed to the plunging of process into LTO regime and usually after 5-6 months the percentage of CO_2 decreased to values in the range 4-9%.

It is worthwhile mentioning that several other ISC processes, operated at small air injection rates, such as Borislav, former Soviet Union[27] and others were in our opinion operated in the LTO operation mode. Actually, at Borislav (air injection rate of 10,000 sm^3/m^3) , although the LTO process is not recognized as such, it was reported that the viscosity of produced oil increased 2-2.5 times on a continuous basis, which again seems to confirm the LTO character of the process.

Given the facts presented the author's belief is that any theories trying to preach the utilization of low air rates in the ISC process have little or no value if there is no concern for the analysis of LTO regime implications. It may lead to a long period of ISC testing, without having the possibility to discern between success and failure. The only exception seems to be the utilization of low air rates just before the end of the pilot life.

Usually, for piloting in-situ combustion, small area patterns are highly preferable to large area patterns. Actually, for a series of tests conducted in patterns of 20-40 acres, frequently the pilot life should be longer than 10-12 years, and the main symptom of the existence of a vigorous combustion front—increase of bottomhole temperature of the producers—may come very late. The examination of the experimental patterns implemented in the Lloydminster area, for instance, showed very large pattern areas, such as 10-30 acres, used in 8 out of 10 cases.[28] In these situations, usually, long response times, coupled with many operational problems caused the stoppage of field tests prematurely. As pointed out in[29] "field evaluation of fireflooding has nearly ceased due to disfavor among the oil industry's upper management." In the author's opinion, this disfavor was the result, on the one hand of large pattern areas, and on the other hand, of too many problems, aggravated by the non-updip location of the pilot.

LIGHT OIL RESERVOIRS ISC APPLICATION

The main aspects of light oil reservoirs ISC application, which differentiate this process from that for heavy oil reservoirs are; the fuel deposition and its nature, the ignition approach and the displacement mechanisms. All these aspects will be addressed in the following.

Light Oil Shallow Reservoirs

A concern for the application of ISC in light oil reservoirs is the existence of sufficient fuel to sustain the combustion. This aspect, generally, is connected primarily with the viscosity of oil and secondarily with the value of current oil saturation. For reservoirs having oil viscosity in the range of 2-6 cP, some field tests showed that the problem of too low oil saturation doesn't seem to exist. For instance, in the case of Ochiuri field[15]—oil viscosity = 6 cP—the experimental pattern was located updip, right in the secondary gas cap, in a block where a conventional gas injection took place for more than 10 years. Although the oil saturation was very low, no difficulty was experienced in the artificial ignition and subsequent propagation of a combustion front. Oxidations of oil free rock samples in the small reactors showed that very frequently in the rock there is an organic material intimately associated with the rock, the so called kerogen, which is capable of providing a part of the needed fuel. Although a lot of laboratory data support this statement, few data are in the public domain. The only published data show that for some laboratory examined rocks this organic material was in the range of 3Kg/m^3-18kg/m^3 rock.[31] As a matter of fact, generally the sedimentary rocks have a certain organic content[32] which may constitute at least 20-30% of the needed fuel.

Another interesting aspect of the application of ISC for light and very light oil reservoirs is that of the value of peak temperature. The Sloss project[33] recorded a peak temperature of 550-600° C. This high temperature, however may be the result of oil resaturating the burned zone, followed by the reburning of the fuel at the second propagation of the front. ISC experiments in light oil reservoir at Ochiuri and Babeni,[15] operated for over 5-6 years, never showed a peak temperature higher than 200° C. However, it should be mentioned that the combustion gas composition seemed to be normal; CO_2 of 15-18%, practically 0% O_2, and an apparent H/C ratio of 1-2.5. Therefore it is possible that for some oils, in the field, the peak temperature can not exceed a maximum temperature, which could be in the range 200-300° C.

Light Oil Deep Reservoirs

The results from table 1a and 1b show favorable AOR obtained for some deep, light oil reservoir ISC processes. Also, it shows that usually the gravity was taken into account by starting the process at the uppermost zone of the reservoir.

For deep oil reservoirs, with temperature higher than 70-80° C the application of the process is a lot easier because usually there is no need for artificial ignition and the control of the process is less difficult. As long as the air is injected in the pay section is OK. It is believed that, the air is forming an active, vigorous combustion front and is displacing oil in any of the layers in which is flowing; of course one still should watch for the impact of LTO, even in this case. There may exist few cases where the process is not as simple as implied above. In any event, the high temperature oil reservoirs are presently the only happy examples where the ISC was applied nonselectively for a multilayered oil formation of substantial thickness as in the case of Midway Sunset, where as many as 6 layers (thickness=120 ft) are operated simultaneously.

For the very light oil reservoirs with high temperatures it is not yet clear what is the nature of the "fuel" which can sustain the process. However, a similitude with the superwet combustion process may be anticipated. If so, the nature of fuel seems to be somewhere between the classical coke and oil. Of course, more laboratory and field testing are needed to clarify the application of ISC for high temperature reservoirs containing very light oil.

Recent Advancements in Kinetics of Oil Oxidation

In-depth studies conducted at University of Calgary revealed the existence of phenomenon of exothermicity gap[34-36] as being the existence of temperature domain (for instance between 250° and 350° C), for which the increase of oxidation rate with the increase of temperature diminishes considerably or even stops. The revealing of the significance of this phenomenon may create premises for explaining the very different behavior of light oil during the ISC. Indeed, it is possible that some light oils have a very high reactivity with small or no exothermicity gap, while other oils can have a very big exothermicity gap and in the field it is difficult or even impossible to exceed the higher boundary value of that gap. More laboratory research, coupled with very focused field tests may be very useful in quantitative description of this aspect and its incorporation in the ISC potential evaluation and numerical simulation. This may bring substantial advances in the area of application of ISC for light oil reservoirs. Actually, only if the exceeding of the gap is possible the burning of the kerogen is possible; otherwise only "the fuel from the oil" has to fully assure the self-supporting capacity of combustion.

For the large exothermicity gap oils, irrespective of the reservoir temperature, the application of spontaneous ignition for the initiation of ISC may not be a good solution. Only a strong artificial ignition will produce the passing of the ISC peak temperature over the higher limit of the exothermicity gap to assure a stable combustion. In figure 10 the exothermicity gap for the Athabasca bitumen is shown, as being the temperature range of 300-500° C, where very few occurrences of peak temperature values were recorded. For a light oil (Countess B) the exothermicity gap was between 310 and 350° C. So, the exothermicity gap may be a reality even for a heavy oil, but perhaps in the field this was not noticed because, usually, the artificial ignition was used, and the temperature during ignition was kept above the higher limit of the exothermicity gap.

Displacement Mechanisms for Light Oil Reservoirs

ISC, like other EOR processes, is a displacement process. From a displacement point of view, compared to the gas miscible flooding, the only essential differences, are that the swept zone is usually completely devoid of oil (the numerous oil saturated small fingers are missing) and it produces some additional oil from the unswept zone due to its heating. Obviously, the mechanism of oil recovery by ISC in the case of light oil, is not the reduction of oil viscosity because this is insignificant and cannot be taken into account. Therefore, the additional oil from unswept zone can not make a significant contribution. Unlike the case of heavy oil, in the light oil reservoirs ISC applications, the conformance factor (CF) of the burning front seems to be high. For instance in the May Libby, Delhi Field, Louisiana project,[37] where the viscosity is 3 cP, and pay thickness 3m, the CF was 100%. In Delaware Childers, Oklahoma,[38] project, with a viscosity of 6 cP, and net pay thickness of 14m the CF was 65%. Also, in the Fry, project,[39] with a viscosity of 40 cP, and net pay thickness of 15m the CF had a very high value. This hypothesis, also, seems to be supported by the behavior of the steam drive processes applied for low and medium viscosity oil reservoirs, where a high vertical and areal sweep efficiency are made responsible for the suitability of some design methods.[40] Definitely, more lab and field research are needed to prove this supposition.

The gravity stable displacement achieved by injecting the air updip is an extremely important aspect of light oil ISC application. The steeply dipping reservoir applications using patterns situated somewhere on the structure have very little prospect of success, even in the case the burning is very active in the front. This is so because of the very serious operational problems in conjunction with the intensive channeling of the front towards the upper part, without displacing too much oil, and due to the low degree of control of the process, including the flow of the oil in the burned out zone as soon as a decrease of pressure occurs.

The recently designed ISC process for the light oil Hackberry field,[41,42] corroborated with detailed laboratory research, can be instrumental to the advancement of knowledge in the area of ISC application for light oil reservoirs.

The most difficult operational problem for the application of ISC for light oil reservoirs is the intensive corrosion of the bottomhole equipment, mainly pumps and tubulars. This problem was recorded in most of the light oil reservoir yet is not a general rule. This problem was specifically discussed for the projects Esperson Dome,[14] Babeni,[15] Willow Draw[43] and Fosterton Northwest,[44] where the pumps had to be changed only after a few days of work. Definitely, the corrosion of the bottomhole equipment is more intensive compared with the case of heavy oil ISC projects. The formation of a thin layer of oil on the tubulars, with a protective role, seems to be a reality for ISC projects for which the oil viscosity is higher than 100-200 cP.

HORIZONTAL WELL ASSISTED IN-SITU COMBUSTION

For the time being, there is a scarcity of data in the area of horizontal well assisted in-situ combustion both for laboratory research and for field testing. However, perhaps in the first detailed paper on this subject, Greaves et al.[45] convincingly demonstrated that the sweep efficiency and consequently the oil recovery increased substantially when using horizontal wells. In a 3-dimensional model they showed that the volumetric sweep efficiency increased from 59% for the vertical wells case to 70% for the horizontal wells case; The oil recovery increased accordingly.

Also, Greaves et al.[46] investigated the use of horizontal well assisted in-situ combustion for the heavy oil reservoirs with an extensive bottom water. The interpretation of these tests are more difficult than for the previous cited tests but still it was demonstrated that in-situ combustion can be an option.

So far, horizontal wells—in conjunction with an in-situ combustion process in the field—were drilled in two

Canadian projects. In both cases the horizontal wells were used as producers. The essential aspects and results of these horizontal wells are presented in the following.

Canadian Examples of Application of Horizontal Wells in Existing ISC Projects

In the first project, Eyehil, Saskatchewan,[47] three horizontal wells with an horizontal leg of 1,000-1,200m were drilled. The wells were drilled after 2 years from the complete cessation of the dry combustion in 8 adjacent, 8ha inverted five-spot project. The combustion process was active for about 10 years, but it was operated with relatively low air rates; at the stoppage time, the oil recovery was 10%. The reservoir is underlined by water, whose height column is as high as 15m ; oil viscosity in reservoir conditions is around 2,000 cP, while the net pay thickness is 5m-8m.

Out of these three wells, one (the first one) had a very good production performance. This well produced for a long time with oil rates of 55-60m^3/d. The good behavior of this well is explained by the fact that it was located very close to the boundary of the project area but didn't intercept any burned zones. The second horizontal well was situated on the other side of the first horizontal well, too far from the project area and probably it was screened by the first one. The third horizontal well intercepted a portion of the burned area and it had a mediocre performance. This behavior was to be expected based on the extensive experience at Suplacu de Barcau [17], where 12 coring vertical wells were drilled in the burned area; None of these 12 wells produced oil.

In the second project, Battrum, Saskatchewan,[48] one horizontal well was drilled in conjunction with the commercial wet combustion process which has been in progress on this reservoir since 1964. This process takes place in a reservoir having a relatively low oil viscosity (70 cP), and a net pay thickness of 9m-18m. The horizontal well was drilled in December 1993 and it has a horizontal leg of 610m. It was positioned between the gas tongue and the water tongue in an exploitation using patterns system. The performance of this well was very good as the oil rate increased 5-10 times (from 3 to 15m^3/d for a vertical well, to 35 to 75m^3/d for the horizontal well), with a decrease in water cut from 60-90% to 20-60%. Another very important advantage of the horizontal well was the substantial reduction of operating problems like sand influx and treating of emulsions. This advantage can be linked with the extremely low drawdown during oil flow towards a horizontal well.

This well revealed another possible new feature of horizontal wells used in the ISC projects; The combustion gases produced by this well contained 12%-13% hydrocarbon gases. In case the well is far from the present combustion front this is just normal. But if the horizontal leg is already at high temperatures the high content of hydrocarbon gases may be due to the vaporization of light hydrocarbon on the horizontal trajectory of the well. Either case, the apparent hydrogen-carbon ratio should be calculated making the correction for the presence of hydrocarbon gases. For example, for the Battrum horizontal well combustion gas composition given in table 5, the apparent hydrogen-carbon ratio is 2.6, when applying the correction for the presence of hydrocarbon gases, while being overestimated at 3.8, when this correction is not applied. The value of 2.6 shows a relatively good quality of burning in the combustion front. Actually, the reduced composition of combustion gases (hypothetically just after passing through the front) must be used for the correct H/C ratio calculation, or alternatively, using the "as recorded values for both combustion gases and hydrocarbon gases percentages, the formula given in [30] should be applied.

Discussion—Other Possible Applications

Given the fact that the heat may be still there even after 7-10 years after the stoppage of active combustion, there are good possibilities to drill horizontal wells in the fields where the ISC project was abandoned long ago. Of course, they may be successful with one condition: if there was a good burning in the formation before the stoppage of air injection. In those cases where the ignition was a problem and/or it was never known if there was a good quality burning, the drilling of horizontal wells is not an option for getting out additional oil from an abandoned ISC process.

As noticed, so far the horizontal wells have been only used as producers. However, the utilization of horizontal wells could be extremely useful as injectors mainly in the low injectivity reservoirs where they can open the door for the application of wet combustion in much more cases. Actually, in the past, a lot of in-situ combustion projects suffered of low injectivity and many of them even failed due to the lack of possibility to assure the minimum air injection rate. It is expected that horizontal well injectors will be used first in the reservoirs where the spontaneous ignition is easily achieved. For the reservoirs with low reservoir temperature and low reactivity oil, for the time being, the use of horizontal wells as injectors can not be contemplated due to the impossibility of igniting the whole horizontal length by artificial means (gas burner or electrical heater). At least the utilization in a conventional manner is not possible. New methods have to be developed. These new methods should account for the fact that generally, the safety measures for the horizontal wells as injectors have to be extremely strict, as the control over the fluids present in the horizontal leg, before and/or during ignition operation, is by far lower than for the vertical wells.

POSSIBLE IMPROVEMENTS OF THE PROCESS

Foam Utilization

For the ISC projects applied to heavy oil reservoirs the volumetric sweep efficiency usually is poor, less than 25%-35%.

Given the ability of foams to achieve very high resistance factors in oil-free rocks[49] it appears that actually the foam could have high efficiency when applied with ISC processes. In this case the other positive element for the foam use is that after 6-7 months from the beginning of the process, the temperature around the air (air/water) injector is low, close to the reservoir temperature. This creates favorable conditions for foam application. Injected in the combustion wells the foam can significantly decrease the gas channelings.

The first foam field testing in Karajanbas field[11,50] gave promising results. Foaming surfactant solutions were injected in 3 combustion wells (belonging to a line drive process) over a 5-month-period of testing. All in all, for 24,000 bbl of surfactant solution, with the concentration of 1-2%, an amount of 55,000 bbl of incremental oil was obtained. The surfactant solution was injected in two batches and was stabilized with a 0.1% water solution of polymer. For the pilot zone, the oil production increased 2.4 times, while water cut decreased by 20-25%.

Taken into account the mechanism of ISC and foam, it is expected that the foam will give better results in the high temperature reservoirs.

Horizontal Wells

It is expected that the big progresses in application of ISC will be due to the combination with the horizontal wells. In fact in a lot of aborted cases the ISC front worked very well and displaced the oil, but due to the very severe problems like sand inflow, emulsion, etc., the vertical producers were not able to produce this oil. If the horizontal wells overcome these problems the ISC becomes a user friendly EOR process. The only problem which still remains when using the horizontal well as a producer is that the combustion front can intersect the horizontal leg close to the heel and can prematurely damage the whole horizontal portion of the well.

Given the fact that thermal protection of the horizontal portion of the horizontal well producer may be difficult, impractical or simply too expensive, it is expected that some research for improvement of superwet combustion may bring substantial advances in the direction of superwet combustion field application. Superwet combustion, with its very moderate "peak temperature," can offer the desired protection to the horizontal well producer. Obviously, nonconventional ISC processes based on the superwet combustion may be very well justified, too. At present stage of superwet combustion knowledge, there is no commercial application of this process.

The advent of horizontal wells, certainly, will produce substantial progress in the area of application of ISC for underground coal gasification (UCG). Today there are only few commercial applications of UCG,[51] and it is interesting to note that these are using the line drive system, with very small distance between wells.[52] It is expected that in the long run, the interchange of knowledge between ISC technology for the oil recovery and ISC technology for UCG will be very beneficial for both areas.

Nonconventional Applications

In the future there is a good possibility that ISC will be used not only like it has been used so far, as a displacement process, but also in a nonconventional manner, either for pre-conditioning the reservoir before other method is applied or for producing nonexpensive heat which can be used, either for upgrading the oil in situ, or in order to simply produce steam in situ, or for some other goals. The use of ISC as a non-displacement process essentially means that the achieving of a good volumetric efficiency will no longer be the main goal. In this situation, for instance, the creation of an oxidation chamber in which to produce in a stable and continuous manner heat, as opposed to the goal of continuously expanding the burnt volume, will be the target. Actually, the UCG is not a displacement process. Therefore, some knowledge from UCG may inspire the development of ISC nonconventional new processes.

CONCLUSIONS

Worldwide, currently, there are more than 14 active full scale ISC projects, which have been in progress for a period of between 8 and 30 years. For the heavy oil reservoirs, the process has been applied in a very wide range of conditions, as a secondary or tertiary method. Recently, the process has been applied commercially in light oil reservoirs.

At least a third of the full scale ISC projects are operated using the line drive well configuration, with a linear ISC front generated at the uppermost zone of the reservoir and being propagated towards the lower zone of the reservoir.

Irrespective of what system—line drive or patterns—is to be adopted, the ISC pilot should be located at the upper part of the reservoir. Compared with the patterns system, the peripheral line drive ISC system offers the advantages of easier operation and evaluation, while providing better oil recovery.

There are good prospects for the application of ISC for high deep reservoirs. The existence of reservoirs with temperatures over 70-80° C is an important favorable factor. To start the process updip, perhaps it is even more important than in the case of heavy oil reservoirs.

Recent field applications of horizontal wells in conjunction with two existing Canadian ISC projects showed promising results, both in the thermal oil production area and as a means to substantially reduce the operational difficulties. Irrespective of the status of the existing ISC project, active or already shut off, the location of the horizontal well should be made such that the burned zone is not intercepted.

ACKNOWLEDGMENT

I express my appreciation to Dr. G. Moore of the University of Calgary and Dr. I. Adamache of the Adamache Petroeng. Ltd. Calgary for their help during preparation of this paper.

REFERENCES

1. Kumar, M.: "Optimizing Steamflood Performance in Dipping Reservoirs," SPE 24080, Western Regional Meeting, Bakersfield, California, Mar. 30-Apr. 1, 1992.
2. "EOR Increases 24% Worldwide Claims 10% of U.S. Production," Annual Production Report, *Oil and Gas J.*, Apr. 20, 1992.
3. Pautz, J. V., C. A. Sellers, C. Nautiyal and E. Allison: "Enhanced Oil Recovery Data Base," NIPER, Bartlesville, Oklahoma, Apr. 1992.
4. Machedon, V., T. Popescu and R. Paduraru: "Application of In-Situ Combustion in Romania," Joint Canada-Romania Heavy Oil Symposium, Sinaia, Romania, Mar. 7-13, 1993.
5. "CO_2 and HC Injection Lead EOR Production Increase," Annual Production Report, *Oil and Gas J.*, Apr. 23, 1990.
6. "EOR Projects Decline, but CO_2 Pushes up Production," Annual Production Report, *Oil and Gas J.*, Apr. 18, 1988.
7. Chu Chieh and E. J. Hanzlik: "Case Histories—Thermal Recovery," Southern Methodist Univ. Inst. for the Study of Earth & Man Enhanced Oil recovery for the Independ. Prod. Symp., Dallas, Oct. 9-10, 1983.
8. Curtis, J. H.: "Performance Evaluation of the MOCO T In-Situ Combustion Project, Midway Sunset Field," SPE 18809, California Regional Meeting, Bakersfield, Apr. 5-7, 1989.
9. Showalter, W. E., and M. A. Maclean: "Fireflood at Brea-Olinda Field, Orange County, California," SPE 4763. SPE Symposium on EOR, Tulsa, OK, Apr. 22-24, 1974.
10 Bocserman., A. A., Y. G. Mamedov and D. G. Antoniady: "Diverse Methods Spread Thermal EOR in U.S.S.R," *Oil and Gas J.*, Oct. 7, 1991.
11. Mamedov., Y. G., and A. A. Bocserman: "Application of Improved Oil Recovery in U.S.S.R.," SPE/DOE 24162. SPE/DOE Eight Symposium on EOR, Tulsa, OK, Apr. 22-24, 1992.
12. Baibakov, N. K., and A. R. Garusev: "Thermal Methods of Petroleum Production." Elsevier Amsterdam-Oxford-New York-Tokyo, 1989
13. "First Commercial Canada Fireflood Okayed for Mobil," *Oil and Gas J.*, Aug. 12, 1968.
14. Pebdani, F. N., D. A. Best and J. E. Mallinson: "Status of Oxygen Fireflooding," 1989 California Regional Meeting of the SPE, Bakersfield, CA, Apr. 5- 7, 1989.
15. Carcoana A., V. Machedon, I. Pantazi, V. Petcovici and A. Turta: "In-Situ Combustion. An Effective Method to Enhance Oil Recovery in Romania," Eleventh World Petroleum Congress, London, Aug. 28-Sept. 2, 1983.
16. Aldea Gh., A. Turta and M. Zamfir: "The In-Situ Combustion Industrial Exploitation of Suplacu de Barcau Field, Romania," The Fourth International Conference on Heavy Crude and Tar Sands, Aug. 7-12, 1988, Edmonton.
17. Carcoana A.: "Results and Difficulties of the World's Largest In-Situ Combustion Process: Suplacu de Barcau Field, Romania," SPE/DOE 20248. Seventh SPE/DOE Symposium on EOR, Tulsa, OK, Apr. 22-25, 1990.
18. Turta A., S. Socol, N. Trasca and N. Ilie: "Application of Cyclic Combustion in Romania," Mine Petrol si Gaze, July 1985 (In Romanian).
19. Hallam, R. J. and J. K. Donelly: "Pressure-Up Blowdown Combustion: A Channeled Reservoir Recovery Process," SPE 18071, presented at 63rd Annual Technical Conference and Exhibition, Houston, TX, Oct. 2 -5, 1988.
20. Jensen, E.: Morgan In-Situ Combustion Project. Unpublished Talk from the Calgary Section CIM Heavy Oil Special Group's Specialists Forum on In-Situ Combustion, Calgary Oct. 25, 1990.
21. Carcoana A., A. Turta, J. Burger and C. Bardon: "Balayage et Recuperation d'un Gisement d'Huile Lourde par Combustion In-Situ," Colloque Internat. sur les Techniques d'Exploitation et d'Exploration des Hydrocarbures, Paris, Dec. 10-12, 1975.
22. Petcovici V.: "La Combustion In-Situ Assure un Taux de Recuperation Eleve dans un Important Gisement D'Huile Lourde de Roumanie. Le Sarmatien de Balaria," Second European IOR Symposium, Paris, France, Nov. 10 -12, 1982.
23. Miller K.: "EOR Pilot Review - Husky Experience," First Petroleum Conference of the South Saskatchewan Section of CIM, Regina, Oct. 6-8, 1987.
24. Moore, G.: "New Strategies for In-Situ Combustion," *J. of Can. Petr. Techn.*, December 1993.

25. Byll, M. L., R. G. Moore., M. G. Ursenbach: "Field Observations of In-Situ Combustion in a Waterflooded Reservoir in the Kinsella Field," *J. of Canadian Petr. Techn.*, September 1993.
26. Toth, M., L. Voll, P. Kalocsai, G. Csajtai, J. Szelenyi: "New Method for In-Situ Combustion of Light Oil and Field Experiments by the Application of New Observing System," Fifth European Symposium on IOR, 1989.
27. Oganov, K. A., B. M. Pavlov: "Opitno-promishlenoe Raboti po Sozdaniiu fronta Gorenia v Borislavskom Pescianike" Neftianoe Hoziaistvo, No. 5, 1970.
28. Moore., G. Personal Communication. CIM Calgary, Oct. 30, 1989.
29. Miller K.: "Improving the success of thermal EOR Projects by Incorporating More Geologic Information," 44th Annual Meeting of the Petroleum Society of CIM, Calgary, Alberta, Canada, May 9-12, 1993.
30. Turta, A., and I. Pantazi: "Development of In-Situ Combustion on an Industrial Scale at Videle Field, Romania," *SPE-Reservoir Engineering*, Nov. 1986.
31. Mehtibeili, R. M., and Z. A. Sultanov: "The Influence of Oil Reservoir Rock Properties on the Oxidation Capacity of the Rock During The In-Situ Combustion Process," Neftianoe Hoziaistvo, No. 2, 1978 (In Russian).
32. Levorsen, A. I,. Geology of Petroleum. W.H. Freeman and Company, San Francisco, 1958, p. 493.
33. Parrish, D.R, C. B. Pollock and F. F. Craig: "Evaluation of C.O.F.C.A.W. as a Tertiary Recovery Method, Sloss Field Nebraska," SPE 3777, Tulsa 1977.
34. Moore, G., J. D. M. Belgrave, R. Mehta, M. Ursenbach, C. J. Laureshen and Xi Kejia.: "Some Insights Into the Low-Temperature In-Situ Combustion Kinetics," Eight SPE/DOE Symposium on EOR, Tulsa, OK, Apr. 22-24, 1992.
35. Ursenbach M., G. Moore., D. W. Bennion and J. D. M. Belgrave: "Laboratory In-Situ Combustion Behavior of Athabasca Oil Sands," Eight Petroleum Conference of the South Saskatchewan Section of CIM, Regina, Oct. 18-20, 1993.
36. Moore., R.G., J. D. M. Belgrave, M. G. Ursenbach, S. A. Mehta and C. J. Laureshen: "A Canadian Perspective on In-Situ Combustion. Joint Canada-Romania Heavy Oil Symposium, Sinaia, Romania, Mar. 7-13, 1993.
37. Hardy, W. C., P. B. Fletcher, J. C. Shepard, E. W. Dittman and D. W. Zadow: "In-Situ Combustion Performance in a Thin High Gravity Oil Reservoir, Delhi Field," SPE 3053, 1970.
38. Barnes , A. L.: "Results from a Thermal Recovery Test in a Watered-Out Reservoir," *J. of Petr. Techn.*, November 1965.
39. Clark, G. A., R. G. Jones and W. L. Kinney: "The Fry In-Situ Combustion Test-Performance," *Trans AIME*, 1965.
40. Jensen, T. B., M. P. Sharma, and H. G. Harris: "A Critical Evaluation of Preliminary Design Techniques for Steam Drive Projects," *J. of Petr. Science and Engineering*, 5 (1990). Elsevier Science Publishers, B. V., Amsterdam.
41. Fassihi, M. R., and T. H. Gillham: "The Use of Air Injection to Improve the Double Displacement Processes," SPE 26374, 68th Annual Technical Conference and Exhibition, Houston, TX, Oct. 3-6, 1993.
42. Yanimaras D. V., A. H. Sufi and M. R. Fassihi: "The Case for Air Injection into Deep, Light Oil Reservoirs," Sixth European IOR Symposium, Stavanger, Norway, May 21-23, 1991.
43. Wilson, Q. T.: "Progress Report—Willow Draw Field. Attic Air Injection Project. Park County, Wyoming," Prepared for the Energy Research and Development Administration under Contract No. ET-76-C-O2-1810, 1979.
44. Mikkelson, P. L., W. C. Cook and G. Ostapovich: "Fosterton Northwest: An In-Situ Combustion Case History," SPE/DOE 17391 SPE/DOE Symposium on EOR, Tulsa, OK, Apr. 17-20, 1988.
45. Greaves, M., A. A. Tuwil and A. S. Bagci: "Horizontal Producer Wells in In-Situ Combustion Processes," *J. of Can. Petr. Techn.*, April 1993.
46. Greaves, M., Y. D. Wang: "3D Physical Modelling of In-Situ Combustion in Heavy Oil Reservoirs with a Bottom Water Layer," 7th European IOR Symposium, Moscow, Russia. Oct. 27-29, 1993.
47. Morgan, R. J.: "Can Horizontal Wells Inject Life Into an Old Combustion Project? Fifth Petroleum Conference of the South Saskatchewan Section, Regina, Oct. 18-20, 1993.
48. Ac, M., B. Ames, R. Grams, F. Pebdani and R. Sandes: "Horizontal Well Economics in a Mature Combustion EOR Project Battrum Field, Saskatchewan, Canada," SPE/CIM 3rd Annual One Day Conference on Horizontal Well Technology and Economics, Nov. 15, 1993. Calgary, Canada.
49. Schramm, L. L., T. A. Turta and J. J. Novosad: "Micro-Visual and Coreflood Studies of Foam with a Light Crude Oil," SPE-Reservoir Engineering, August 1993.
50. Abasov., M.T., and T. V. Kishmetov: "Oil Field Development Using In-Situ Combustion with Foam Systems and Alkaline Solutions," Sixth European IOR Symposium, Stavanger, Norway, May 21-23, 1991.
51. Davis, B. E., and J. W. Jenings: "State-of-the-Art Summary for Underground Coal Gasification," *J. of Petr. Techn.*, January 1984.
52. Skafa, P.V.: Underground Coal Gasification (In Russian). Gostoptehizdat Nauk-Tehn. Izdatelstvo po Gornomu Delo, Moskow, 1960.

TABLE 1a. USA COMMERCIAL ISC PROCESSES

FIELD, COMPANY	DEPTH FT	PERM MD	OIL VISC CP	INJ. WELLS	PROD.WELLS	DAILY OIL PROD. BY ISC BOPD	AIR/OIL RATIO SCF/BBL	INJ. PRESSURE PSI
W.NEWPORT, Mobil[a]	1,600	750	750	36	139	980	10,700	200
LOST HILLS, Mobil[c]	300	1790	410	7	45	520	6,200	-
MIDWAY SUNSET, Mobil[a]	2,700	1,500	110	3/up	31	900	6,700	800
MIDWAY SUNSET,S FE ENERGY[a]	1,700	1,300	5,000	10	40	700	-	-
S. BELRIDGE, Section 12,M.[c]	1100	3000	1600	2	?	900	6,000	>500
BELLEVUE,Texaco[a]	400	650	660	15	85	420	16,300	250
W. HEIDELBERG, Chevron[a]	11,300	85	6	3/up	9	400	10,000	3,700
FOREST HILL,GO.[c]	5,000	950	1,060	21	100	400	-	2,000
BUFFALO, Koch Exploration[a]	7,650	20	2	9	26	930	7,000	4,400
BREA OLINDA[c]	3,300	300	20	2/up	20	650	7,700	1,000

TABLE 1b. COMMERCIAL ISC PROCESSES OUTSIDE USA

FIELD,COMPANY, COUNTRY	DEPTH FT	PERM MD	OIL VISC CP	INJ. WELLS	PROD.WELLS	DAILY OIL PROD. BY ISC BOPD	AIR/OIL RATIO SCF/BBL	INJ.PRESS. PSI
KARAJANBAS, Kaz.[a]	1,100	500	450	78/LD	364	6,000(?)	-	-
BALAHANI, Azer.[a]	910	500	140	6/up	35	600	6,700	500
BATTRUM, Mobil, CAN.[a]	2,900	930	70	25	151	6,900	10,000	400
MORGAN, Amoco, CAN.[s]	1,940	4,400	8,100	9	35	940	-	-
SUPLACU DE BARCAU, ROM.[a]	400	2,000	2,000	132/u-L	527	9,000	12,300	200
W. VIDELE, Sa 3c, ROM.[a]	2500	900	100	19/u-L	50	610	17,000	600
E. VIDELE, ROM.[a]	2,100	1,200	100	33/u-L	89	660	21,000	700
W. BALARIA,ROM.[a]	2200	500	116	22	60	820	24,500	850
E. BALARIA,ROM.[a]	1,500	500	416	15/u-L	47	550	22,500	850

LEGEND

[a] = active; [s] =suspended; [c] = completed
GO = Greenwich Oil; Kaz.= Kazakhstan, former Soviet Union; Azer. = Azerdbaidjan, former Soviet Union
up - ISC process started from the upper part of reservoir
LD - ISC process using the line drive system
u-L - ISC process started from the upper part of reservoir, using the line drive system
NOTE: The values from this table were compiled from references 2-16.

Table 2.

THE MAIN FEATURES OF THE COMMERCIAL PROCESSES LISTED IN TABLES 1A AND 1B:

- **West Newport:** The first experimental patterns were located at the upper part of the reservoir, the remainder were isolated patterns; very low well spacing was used, less than the 2.5 acres: low pressure process (injection pressure less than 200 psi)

- **Midway Sunset** : The nonselective oil production by ISC of a multilayer formation comprising 6 layers; initiation of ISC by spontaneous ignition.

- **South Belridge:** Both ISC and steam drive applied commercially on this reservoir. Burned area three times larger than pattern area.

- **Bellevue:** Typical wet combustion, applied in patterns. Very low well spacing was used, less the 2.5 acres: low pressure process (injection pressure less than 250 psi)

- **W. Heidelberg:** The deepest ISC process (11,300 ft). All three injectors were located at the up-dip.

- **Forest Hill** : The most complete testing of the enriched air ISC process was conducted; its feasibility was demonstrated.

- **Buffalo:** The first ISC commercial application in a carbonate reservoir with very low permeability.

- **Brea Olinda:** The air injectors were located at the upper part of the block, whose dip is very high (45 degrees).

- **Karajanbas:** The fastest development from a pilot to a very large commercial ISC operation. Both ISC and steam drive are applied commercially on this reservoir.

- **Balahani** (the complete name: Balahani-Sabunci-Ramani): All six air/water injectors are located at the upper part of the block.

- **Battrum:** Wet combustion with relatively high water/air ratio. ISC operated with relatively high air rates in the early life of the process.

- **Morgan:** Pressure cyclic ISC process. A significant thermal upgrade of the oil was recorded.

- **Suplacu de Barcau:** Very low well spacing is being used, less the 2.5 acres: low pressure process (injection pressure less than 200 psi). The process displays the biggest ISC front (5.3 miles), associated with the line drive operation.

- **W. Videle:** ISC applied tertiary after waterflooding. The first commercial operation using separated and simultaneous propagation of two ISC fronts, for two separated and superimposed layers.

- **E. Videle:** Commercial operation for a low pay thickness reservoir (10 - 20 ft)

- **W. Balaria:** On the same reservoir, commercial operation using both patterns and line drive, for different zones.

- **E. Balaria:** The reservoir was put directly in commercial ISC operation using a line drive system.

TABLE 3. SUPLACU DE BARCAU RESERVOIR PROPERTIES

SAND CHARACTER	Unconsolidated
DEPTH, ft(m)	115-720 (35-220)
NET PAY, ft(m)	33-53 (10-16)
DIP, DEGREES	3-8
POROSITY, %	32
ABSOLUTE PERMEABILITY, md(um2)	1850(1.85)
INTERSTITIAL WATER, %	15
RESERVOIR TEMPERATURE,°C	18
OIL VISCOSITY (at 18°C), mPaS	2000
OIL GRAVITY, API(Kg/m^3)	16(960)

TABLE 4. DURATION BETWEEN ISC PILOT TEST START AND THE INITIATION OF COMMERCIAL ISC PROJECT FOR FIVE ROMANIAN PILOT TESTS

PROJECT	NO OF EXPERIM. PATTERNS	PATTERN(S) AREA ACRES	DURATION BETWEEN PILOT INITIATION AND START OF COMMERCIAL ISC OPERATIONS, YEARS
SUPLACU	1/P, 6/SC	1.25(5)	6
W.BALARIA	4/P, 6/SC	2.5	7
E.BALARIA	0	-	DCA
VIDELE EAST	2/P	25	7
OCHIURI	1/P	3	8

LEGEND

P = PILOT
SC = SEMICOMMERCIAL
DCA = DIRECT COMMERCIAL APPLICATION

TABLE 5. COMPOSITION OF THE COMBUSTION GAS RECOVERED THROUGH THE BATTRUM HORIZONTAL WELL - MAY 15, 1993 -

GAS COMPOSITION	AS RECORDED	REDUCED
N_2, %	74.8	85.64
CO_2, %	11.03	12.63
CO, %	0.45	0.52
O_2, %	1.06	1.21
C_1, %	11.69	-
C_2,% - C_3, %	0.97	-

The uncorrected (for the presence of hydrocarbon gases - based on "as recorded" composition for N_2, CO_2 , CO and O_2) value of apparent H/C ratio is 3.8

The corrected (for the presence of hydrocarbon gases) value of apparent H/C ratio is 2.6

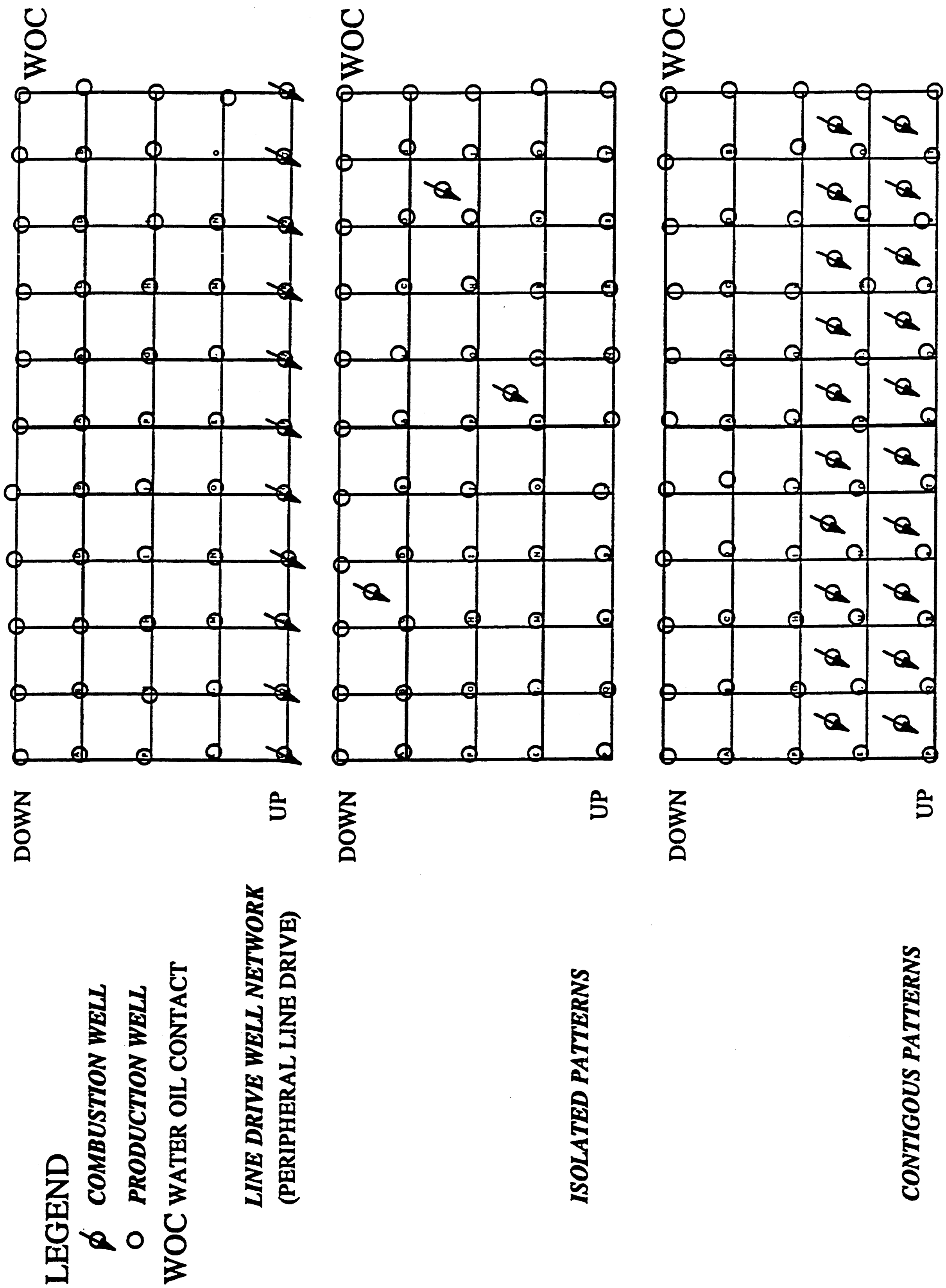


FIGURE 1. THREE WAYS OF APPLYING FIREFLOODING(IDEALIZED OIL RESERVOIRS)

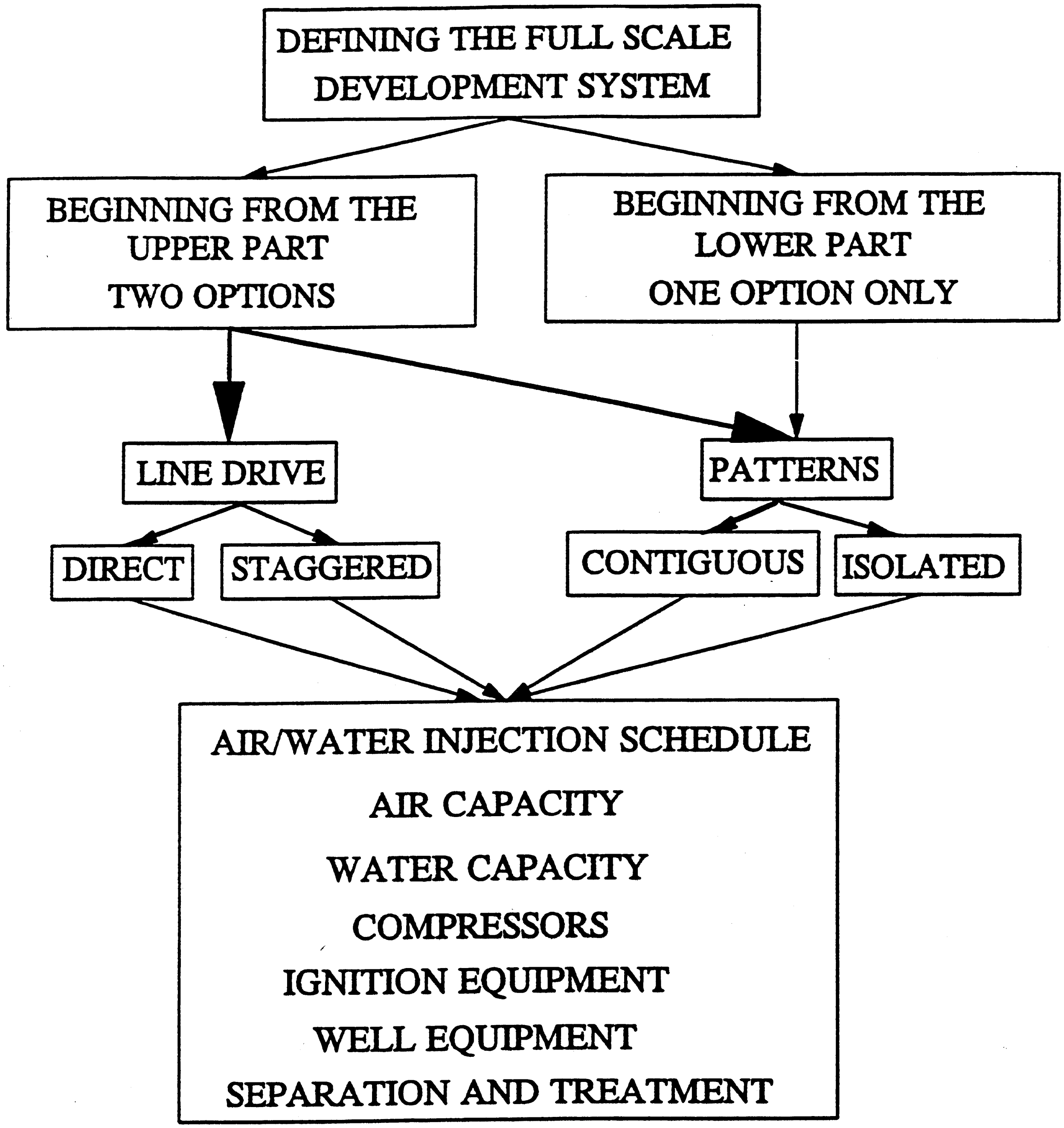


FIGURE 2. THE OPTIONS FOR EXPANSION OF ISC PILOT TO FIELD SCALE OPERATION

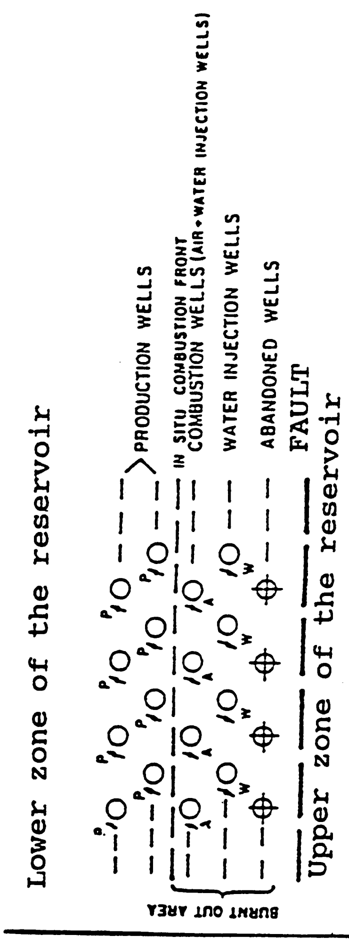


Fig. 3—Staggered line drive in-situ combustion.

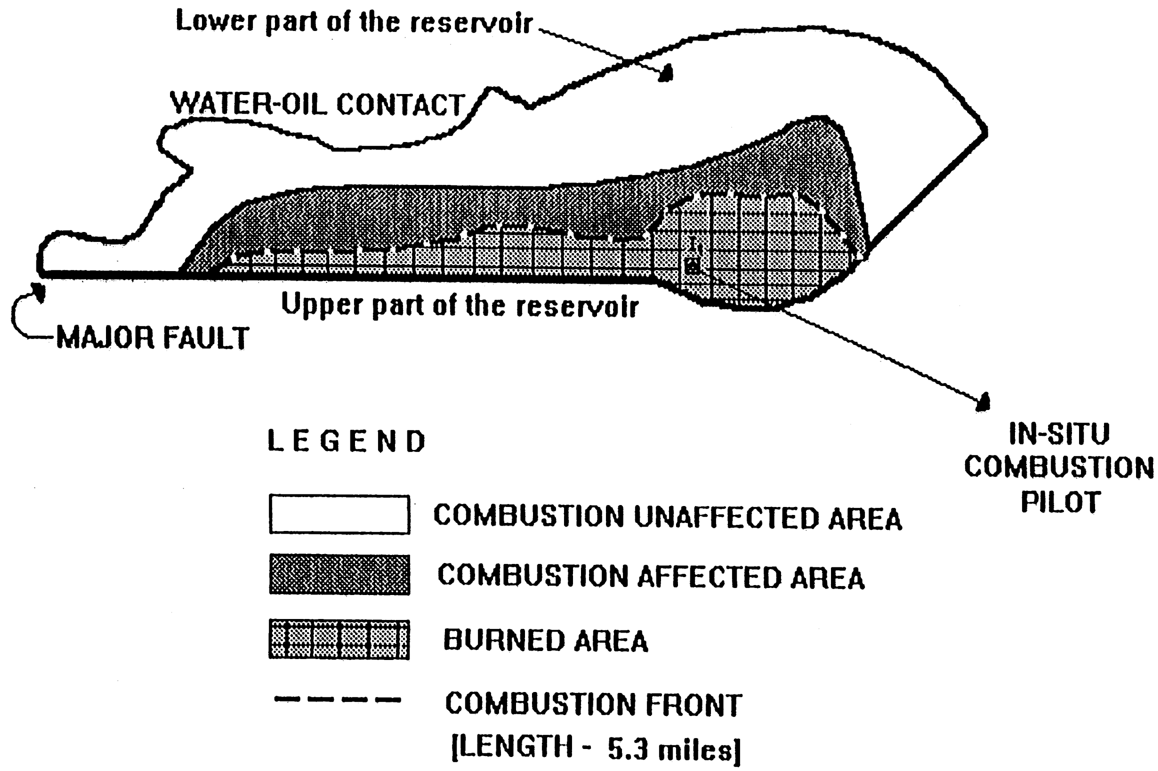


FIGURE 4. SUPLACU DE BARCAU FIELD. AREA AFFECTED BY IN-SITU COMBUSTION LINE DRIVE COMMERCIAL EXPLOITATION AS OF JANUARY 1ST, 1990. [4]

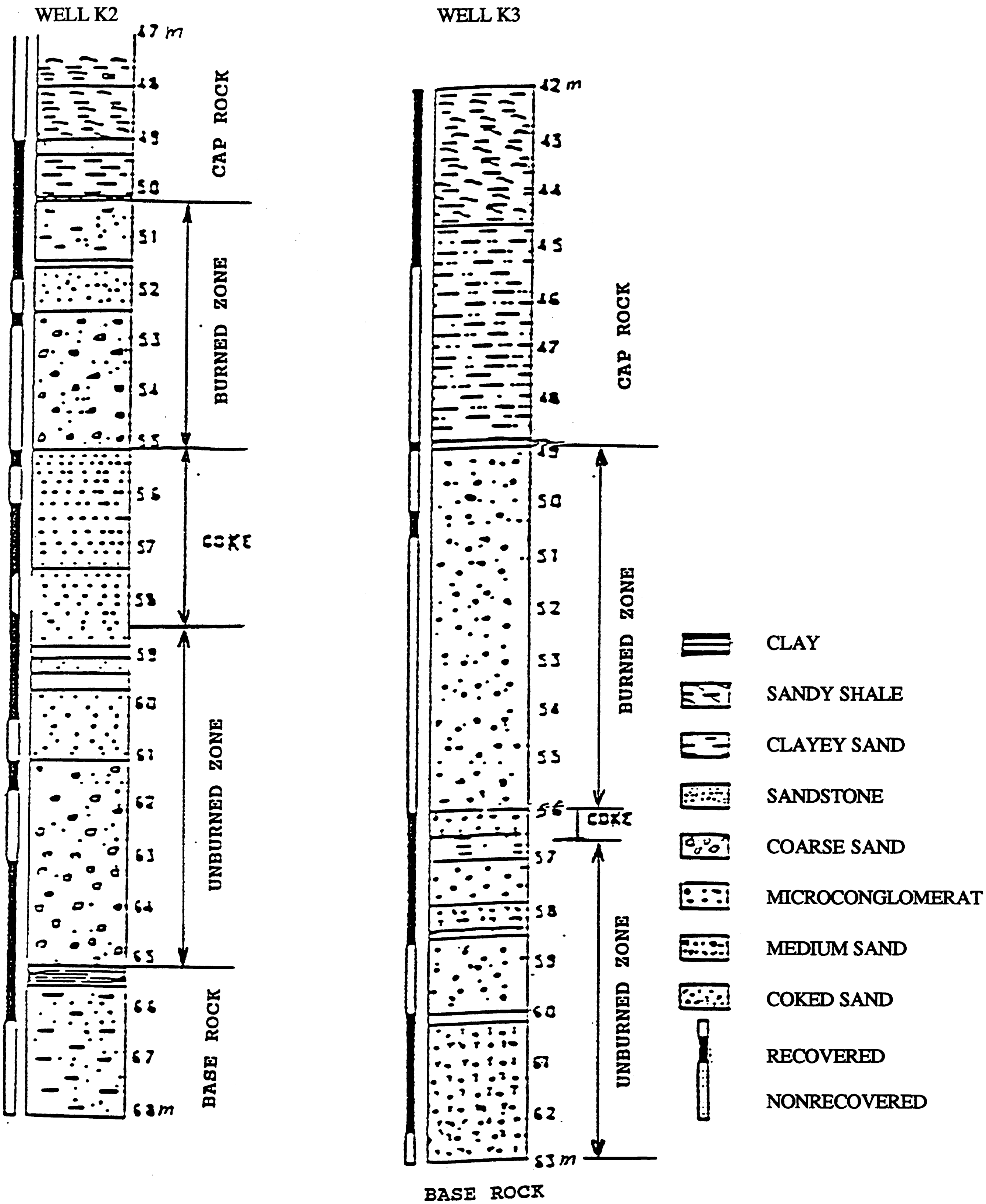
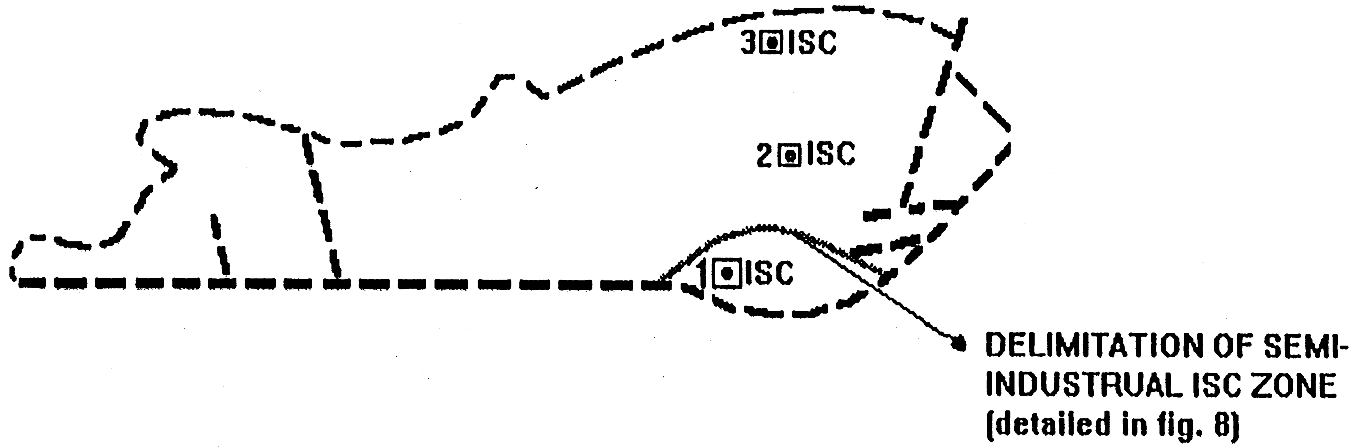


FIG. 5. CROSSECTION THROUGH CORING WELLS K2 AND K3 SUPLACU DE BARCAU, LOCATED IN THE FIRST ISC PILOT [21].



LEGEND

— — WATER OIL CONTACT

▬ ▬ FAULTS

ISC – IN-SITU COMBUSTION PILOT

NOTES:

NO.1 PILOT-UP: AOR= 8422 SCF/BBL

NO.2 PILOT-MIDDLE: AOR= 16844 SCF/BBL

NO.3 PILOT-DOWN: AOR= 22458 SCF/BBL

FIGURE 6. SCHEMATIC MAP OF THE SUPLACU DE BARCAU FIELD WITH THREE DIFFERENT LOCATIONS OF IN-SITU COMBUSTION PILOT TESTS.

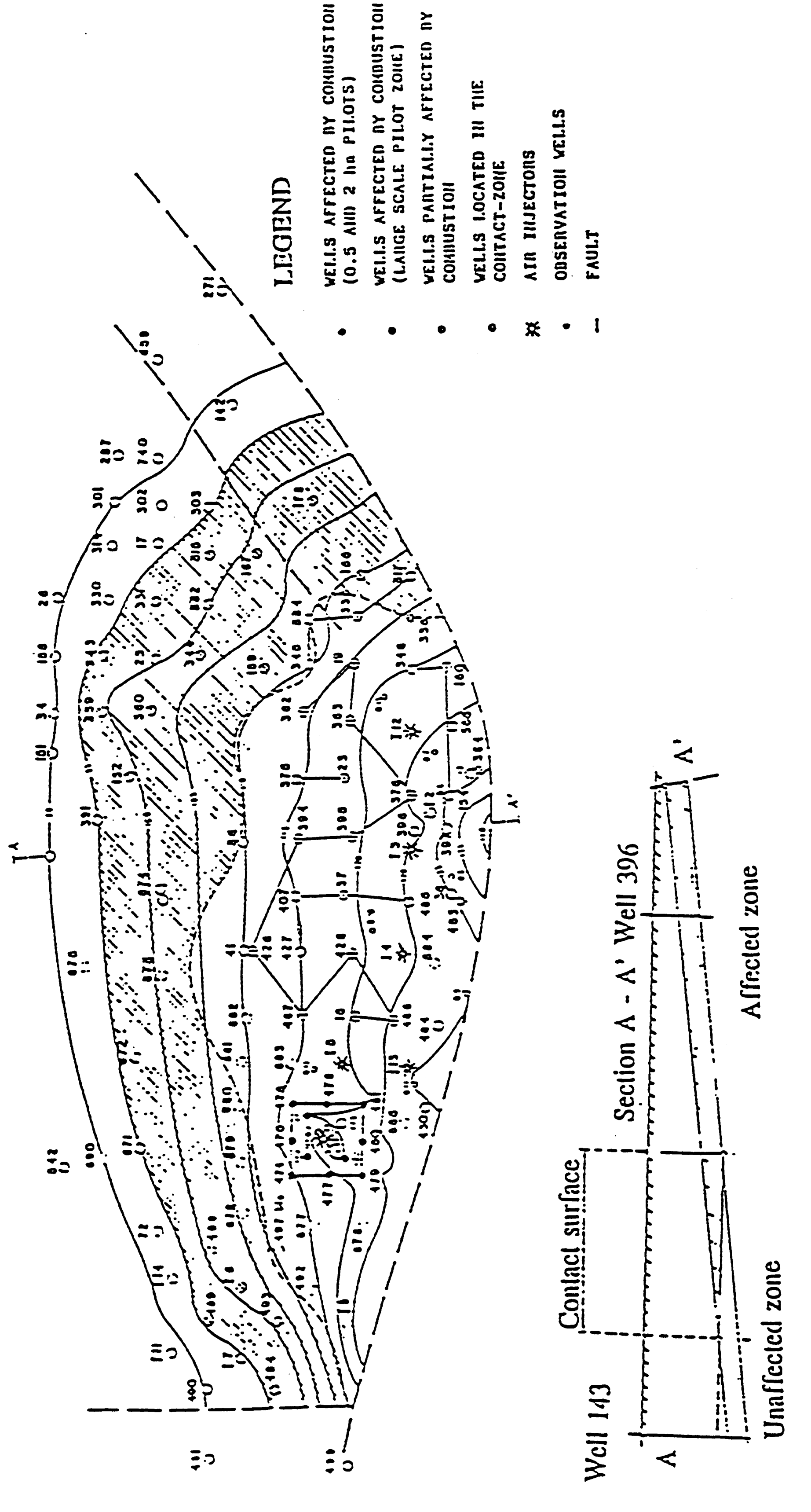


FIGURE 7. SUPLACU DE BARCAU FIELD. IN-SITU COMBUSTION SEMI-COMMERCIAL AREA AS OF JULY 1970, SHOWING THE ZONATION OF AREA IN VIEW OF CALCULATION OF OIL RECOVERY [21].

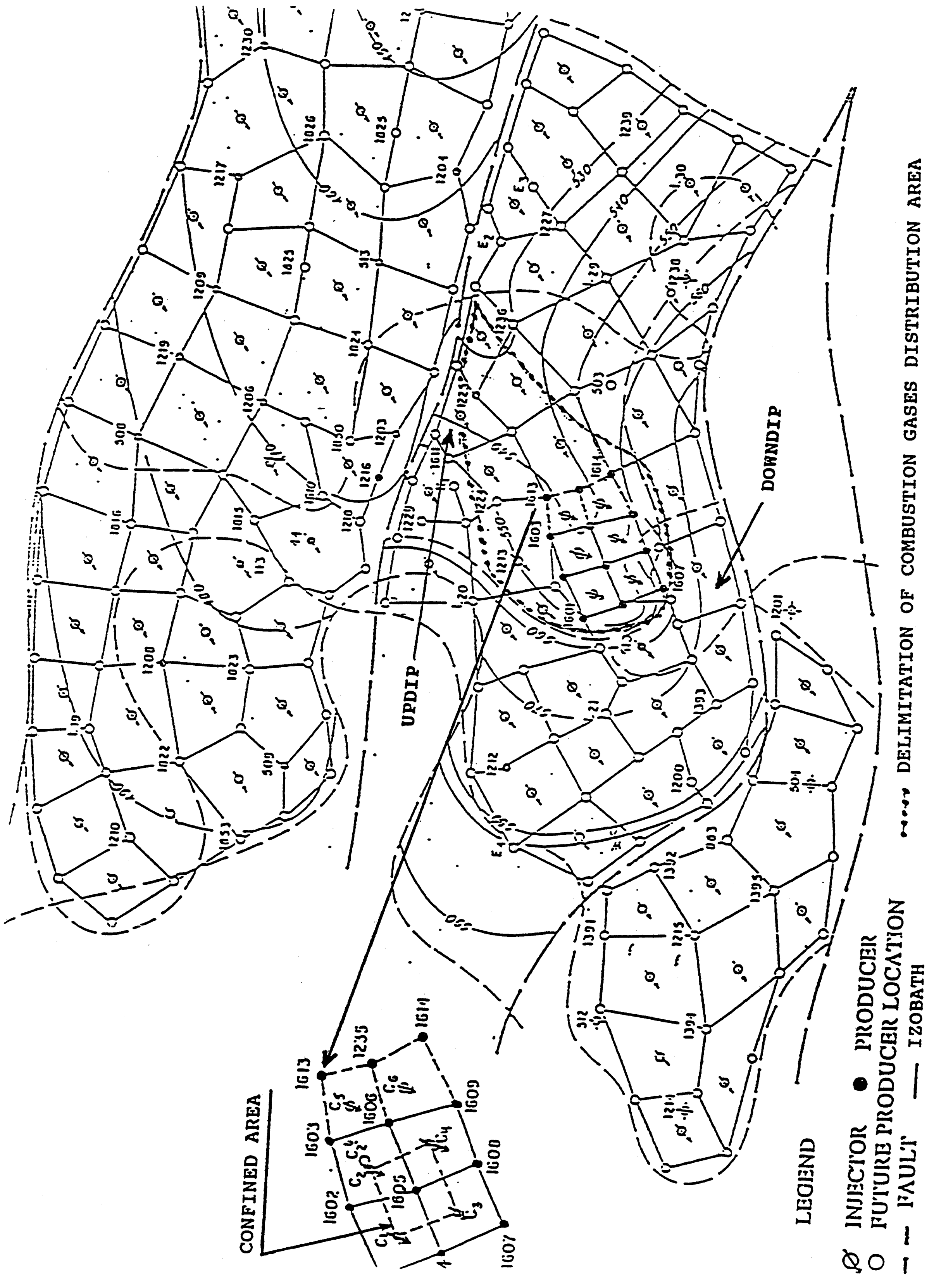


FIGURE 8. BALARIA FIELD. LOCATION OF IN-SITU COMBUSTION PILOT [22]

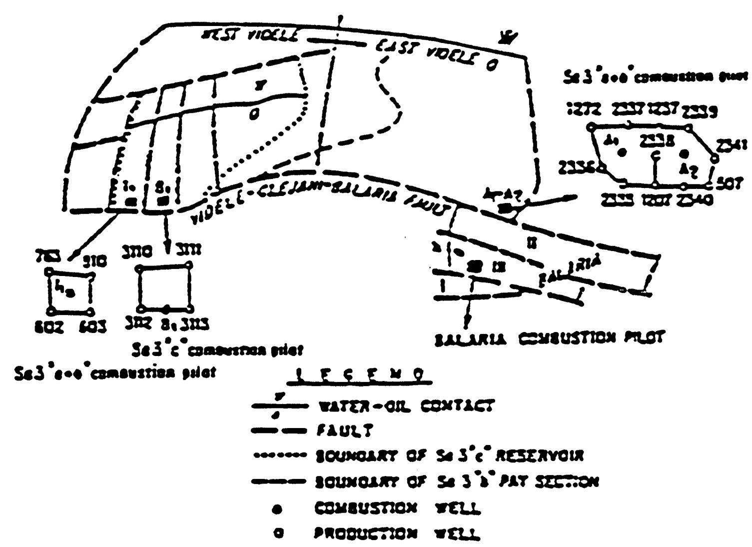


Fig. 9.- Videle/Balaria field-schematic map showing the location of the experimental combustion patterns [30]

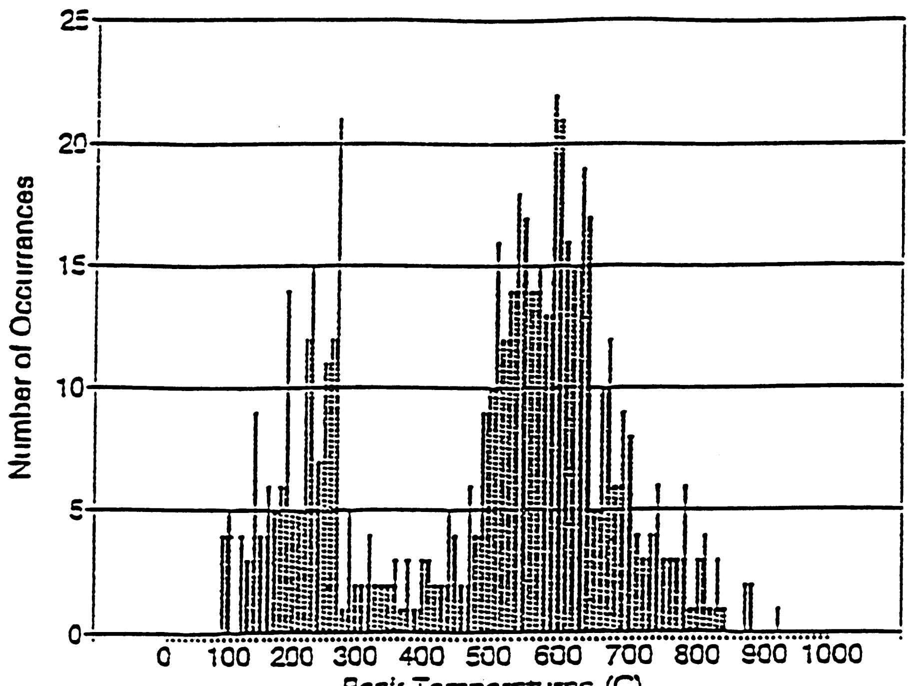


Fig. 10 - Frequency distribution of observed peak temperatures by temperature zones for over 50 Athabaska oil sands in-situ combustion tube tests [35]

No. ISC 4 DOE/NIPER

DOE Cost-Shared In Situ Combustion Projects Revisited

by P. S. Sarathi and D. K. Olsen, NIPER/BDM-Oklahoma, Bartlesville, Oklahoma

This paper was presented at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

As part of its enhanced oil recovery (EOR) program, the U.S. Department of Energy (DOE) and its predecessor organizations sponsored several cost-shared in situ combustion projects in the 1960s and 1970s. The goal of these projects was to evaluate the technical and economic feasibility of in situ combustion as a thermal oil recovery technique and provide information in the public domain as a means of reducing the risks associated with these high cost ventures.

This study reviewed specific features of the cost-shared demonstration and experimental projects, and examined the causes that led to their success or failure. The failed projects were compared with the successful projects under similar settings to further document why these projects failed. The lessons learned were detailed.

The projects examined include: (1) Appalachian Area In Situ Combustion Projects in New York and Pennsylvania; (2) Little Tom Thermal Project, Zavala County, TX; (3) Paris Valley Thermal Project, Monterey County, CA; (4) Bodcau (Bellevue) In Situ Combustion Project, Shreveport, LA, (5) Lynch Canyon Thermal Project, Monterey County, CA; and (6) Bartlett In Situ Combustion Experiment, Labette County, KS. Except for the Bodcau Project, all other projects failed due to various technical reasons, such as failure to achieve self-sustained combustion front, operational problems, etc. The Bodcau Project, however, was commercially successful and provided valuable information on how to engineer a successful in situ combustion pilot.

References, tables and illustrations at end of paper.

INTRODUCTION

In situ combustion or fireflooding as an oil production technique has been practiced since the 1930s and has an interesting and colorful history. The process was patented in the U.S. in 1923, and the first field test in the U.S. was undertaken in 1951. Since then it has been extensively studied both in the laboratory and in the field. The process mechanisms are fairly well understood. However, the process of burning the oil in the reservoir is significantly more complicated than igniting and burning the reservoir. Since the process is applicable to reservoirs not amenable to other EOR techniques, it was promoted as "the oil recovery technique" in the 1950s and 1960s. As a consequence, several field projects were implemented without due engineering and/or geological considerations. As a result, only a few fireflood projects achieved technical and economic success. Failed projects vastly outnumbered the successful projects. Discouraged by failures, operators began to shun this oil recovery technology. This led to a steep decline in the implementation of newer fireflood projects in the U.S. since the 1970s.

Analysis of the successful in situ combustion projects, however, indicates that the process is applicable to a wide range of reservoirs, and the chances of failure can be minimized by careful selection of the reservoir and by adopting prudent engineering practices. To encourage operators to consider implementing this proven oil recovery process in their reservoir and to develop guidelines for conducting successful projects, DOE and its predecessors (Bureau of Mines, Energy Research and Development Agency [ERDA]) sponsored several cost-shared in situ combustion demonstration projects in various parts of the U.S. These projects were implemented in reservoirs with widely differing rock and fluid characteristics and covered the major oil producing provinces in the U.S. While most of these projects were not successful, they provided valuable experience to be used to minimize failure of future projects.

INTENT OF PAPER

The purpose of this paper is to review the government-industry cost-shared demonstration projects and to document the lessons learned. The projects examined include: (1) Appalachian Area In Situ Combustion Projects in Pennsylvania and New York; (2) Little Tom Thermal Project, Zavala County, TX; (3) Paris Valley Thermal Project, Monterey County, CA; (4) Bodcau (Bellevue) In Situ Combustion Project, Bossier Parish, LA; (5) Lynch Canyon Thermal Project, Monterey County, CA; and (6) Bartlett In Situ Combustion Experiment, Labette County, KS. The history and performance of these projects are briefly reviewed and the results discussed.

With the exception of the Bodcau Project, all other projects failed technically for various reasons. The Bodcau Project was both technically and economically successful. In reviewing previous projects, information leading to choices that became critical decisions were not available in the public domain even though these were government or government-industry cost-shared projects. Since project failures are rarely well documented, the authors inferred and drew conclusions based on available information.

The failed projects are also compared with the successful projects under similar settings to further document why these projects failed.

PROJECT DESCRIPTION

Appalachian Area In Situ Combustion Projects (1958–64)

During the period from 1958 to 1964, the U.S. Bureau of Mines (USBM), in cooperation with the Bradley Producing Company and Quaker State Refining Corporation, conducted three in situ combustion tests in the Pennsylvania grade crude oil reservoirs. The objectives of these tests were to determine whether the reservoir containing paraffin-based crude could sustain and propagate a flame front through the oil-bearing sandstone, and to determine what process variables influence the technical and economic viability of the project in such reservoirs.

Bradford Sand Combustion Project[1]

This project was conducted on a waterflooded lease during the summer of 1958 by the Bradley Producing Corporation beginning June 23, 1958, in Bradford sand at the Knight Farm lease, Allegheny field, near the town of Bolivar in southwestern New York. The primary objective of the test was to assess the feasibility of starting and moving combustion front in a waterflooded, low-permeability sand containing high gravity paraffinic crude and to learn if satisfactory air injection rate could be achieved in such reservoirs.

Prior to undertaking the field test, the operator performed combustion tube runs under various conditions to investigate the combustibility of Penn grade crude and air requirements. The tests were performed in a 6" diameter by 60" long steel tube packed with crushed Bradford sand with a porosity ranging from 20% to 35%, permeability from 2 to 4 D and oil saturation from 35% to 70%. These tests proved that it was possible to ignite the crude and move the combustion front along the length of the tube. The oxygen utilization was high enough to warrant a field test.

The field test was carried out in a 4-acre elongated five-spot pattern. The field discovered in 1870 was waterflooded to depletion ten years prior to the test. The average oil saturation at the test site prior to the test was 35.1%, or 420 B/ac-ft. The average reservoir and fluid properties are shown in Table 1. Figure 1 shows the well pattern used in the combustion test.

The operator, using an electrical downhole igniter, made five separate attempts to ignite the injection well. In each case the air was injected until the injection rates were stabilized and then the igniter turned on. In the first three attempts, the igniter failed soon after the start due to mechanical and electrical problems. In the fourth attempt the igniter operated perfectly. However, the igniter failed to ignite the formation, as evidenced by the analysis of produced gas at the pattern well. The produced gas analysis failed to show a reduction in produced oxygen and an increase in produced carbon dioxide. The test was terminated after 37 days of igniter operation.

Since the combustion tube runs showed that the Bradford crude could be burned, the operator concluded that the ignition failure in the field is not due to the marginal burning characteristics of the crude, but because of a lack of fuel near the wellbore as a result of earlier ignition attempts. Therefore, 200 gal of an enriched fuel mixture containing 39° gravity naphtha and a viscous extract of cylinder stock was injected into the well prior to the fifth ignition attempt. Unfortunately, the wellbore exploded during the ignition attempt, and resulted in the abandonment of the project. The summary of the field tests data is shown in Table 2.

Venango First Sand In Situ Combustion Test[3]

Contending that the results of the Bradford sand in situ combustion experiment are inconclusive and failed to provide information on the applicability of the combustion process in Pennsylvania grade crude oil reservoirs, the USBM decided to proceed with additional field experimentation.

The selected test site for the second test was the Quaker State's Hunter lease in the Goodwill-Hill, Grand Valley Field, Warren County, PA, about 10 miles northeast of Titusville, PA. The test site was chosen based on its reservoir characteristics, past primary and secondary operation history, well spacing, sand depth, and condition of existing wells.

In selecting the test site, USBM avoided leases that were previously waterflooded. It was believed that a waterflooded reservoir would not be suitable for an underground combustion experiment because of low oil saturation and the quenching effect of water on the combustion front. The Goodwill Hill-Grand Valley field is underlain by the first and third sands of the Venango Oil Sand Group. The combustion project was initiated in the first sand at a depth of 400 ft. At the cessation of the primary production, secondary recovery was initiated in the first sand by air-gas injection. The secondary recovery operation (pressure maintenance by air-gas injection) was continued outside the project area while the combustion project was implemented. It was believed that an air-saturated sand body would be more amenable to combustion front propagation than a water-saturated formation. The average reservoir and fluid properties are shown in Table 3. Figure 2 shows the well pattern used in the combustion test. The well pattern consisted of a slightly irregular inverted five-spot pattern on 0.85 acre.

An injection well (center well) was drilled and completed by setting 7-in. casing at the top of the sand and cemented to the surface with a heat-resistant cement. The four corner wells (Wells Nos. 21A, 4A, 17 and 20A) were cleaned out with cable tools to existing depth, recompleted by casing through and perforated over the entire interval of the first sand. Fifty barrels of a low gravity crude oil were injected into the formation around the injection wellbore to assure adequate fuel for combustion. A bottomhole gas fired heater was utilized for ignition.

An air-natural gas mixture of 231,000 scf at 185 psig wellhead pressure was injected into the formation over a 36-hour period prior to ignition starting July 1961. Natural gas constituted 3% of the total gas volume injected. The heating value per cubic ft of mixture injected was 15 Btu. The mixture was ignited and the air-gas injection was maintained at the rate of 8,675 scf/hr for nine additional days. During this period, the oxygen content of the produced gas gradually decreased from 20.5% to 16% by volume and the carbon dioxide content increased from 0.6% to 3% by volume, indicating a slow rate of combustion. The injection rate and Btu content of the air-gas mixture was then varied in an attempt to sustain and propagate the combustion front. Natural gas injection was continued for 95 days after the start of ignition. A total of 1.2 MMscf of natural gas was injected into the formation.

The natural gas injection was discontinued because of apparent low combustion efficiency, poor oxygen utilization, and injected natural gas bypassing the combustion front.

Prior to termination of natural gas injection, the air injection rate was decreased to 120 Mscf/D in an attempt to improve combustion efficiency by increasing the contact time between the injected air and the fuel. However, lowering the air injection rate caused the air from surrounding area beyond the experimental pattern to migrate into the pilot area causing changes in the composition of the produced gas. The amount of oxygen and carbon dioxide in the produced gas began to increase and decrease, respectively, as a result of increased dilution. The amount of outside dilution was very dependent upon injection rates and pressure.

The air injection was continued after the termination of natural gas injection. However, the continued air injection did not change the oxygen and carbon dioxide content of the produced gas and the operation was terminated in January 1962, seven months after the initiation of combustion. A total of 38 MMscf of air was injected after natural gas injection was terminated. During the experiment, total gas (air and natural gas) injected was 88.9 MMscf, and a total of 96 MMscf of gas was produced.

During the test, oil production averaged 0.75 barrels per well per day (B/W/D) for the pattern test wells. This was slightly over the average of 0.72 B/W/D prior to the commencement of the experiment. This slight increase in production was probably due to increasing of air injection rate during the experiment, which was considerably higher than the 50 Mscf/D usually injected during the secondary operation.

Following the termination of the combustion experiment, a gas tracer test (using krypton 85) and postcore analysis were carried out to determine (1) vertical extent of thermal front and degree of combustion in the vicinity of the injection wellbore, (2) burnout radius, and (3) the volume of air being produced from outside the test site. The results of the tracer tests were deemed unreliable because most of the tracer escaped into a more shallow sand section creating anomalous pressure distributions and flow patterns within the reservoir. These tests, however, suggested that much of the injected air had migrated out of the test pattern through a highly permeable, low fluid-saturated reservoir interval, thus starving the combustion front of needed oxygen.

Core taken from postexperiment core well drilled 14 ft from the ignition well showed no evidence of combustion.

The measured oil saturation was much higher than the average pilot area oil saturation, suggesting that the higher saturation may be the result of the condensation of the vaporized oil from the vicinity of the injection well (Well 2A). The absence of combustion was attributed to the inadequate fuel deposition needed to sustain combustion.

Venango Second Sand In Situ Combustion Test[3]

Despite the failure of its earlier in situ combustion field experiments, USBM proceeded with a third in situ combustion field experiment in the Appalachian area to establish the technical viability of the process in high gravity, low viscosity, paraffinic crude reservoirs. The selected site for this third field trial was the second Venango sand of the Reno oil field, near Reno in Venango County, PA. The trial was conducted again in cooperation with the Quaker State Oil Refining Corporation, Bradford, PA.

The Reno area was selected principally because the area had not been subjected to any secondary recovery operation, such as the waterflood or air injection operations, and as such, likely to have higher oil in place. USBM believed that a higher post primary oil in place was more likely to enhance the chances for a successful in situ combustion at the test site. The average reservoir and fluid properties are shown in Table 4. The well pattern for the test was an irregular five-spot that enclosed 1.61 acres (Fig. 3).

Two attempts were made at the test site to ignite and propagate the firefront. The first attempt was made in August 1962 and terminated in January 1963 when it was realized that self-sustained combustion could not be established in the formation under existing conditions.

Prior to the second ignition attempt, existing well 2Q (see Fig. 3) was reconditioned and cased with 4 1/2-in. OD pipe and perforated over the bottom two-thirds of the formation. Air-natural gas mixture was injected into well 2Q for 40 days at an average rate of 100 Mcf/D at 700 psi. At the end of air injection, the well was ignited to preheat the sand before injecting crude oil to resaturate the wellbore vicinity. A total of 206 bbl of 37° API Midcontinent asphaltic base crude oil was injected into the formation over a 25-day period at an average rate of 8.25 bbl/D and an average wellhead pressure of 639 psig. Twelve days after crude oil injection was started, the oil broke through at well 4Q. It was estimated about 30 bbl of Midcontinent crude was produced from 4Q prior to final ignition.

After crude oil injection was terminated, air (containing 3% by volume of natural gas) injection was re-initiated into well 2Q at an average injection rate of 135 Mscf/D at 780 psig. Fifteen days after the start of air injection, the air-natural gas mixture was ignited chemically. Fire was maintained in the wellbore for 29 days when natural gas injection was stopped. In the 29 days of wellbore burning 95,150 scf of natural gas and 2,635 MMscf of air was injected. O_2 and CO_2 production from wells 1Q, 4Q and 115 were monitored. The CO_2 content of the gas increased and O_2 content decreased during the ignition period. However, the trend reversed when natural gas injection was terminated. The project was terminated in January 1964 due to poor combustion efficiency from low oil saturation.

At the termination of the project, four wells (Wells TCW 1, 2, 3, and 4) were drilled and cored to determine the extent of burning in the formation. Examination of the cores indicated that heatfront has been moved to about 42 ft from the injection well. Oil production during the experiment increased by about 0.2 B/W/D, and this increase was believed to be the result of air drive rather than an advancing combustion zone. The produced oil had a very strong odor of oxidized hydrocarbons, which is believed to have resulted from the low temperature oxidation reaction of the injected Midcontinent crude.

Little Tom Thermal Recovery Project (1975–1976)[5]

After the oil crisis of 1973, the Energy Research and Development Agency (ERDA, predecessor to U.S. DOE) in 1974, initiated an "enhanced oil recovery (EOR) program" aimed at demonstrating economic recovery of oil from mature or difficult to produce reservoirs through the application of newer or improved oil recovery techniques and to have a way to reduce the U.S. reliance on imported oil. The program was designed to maximize the participation of private industry by awarding cost-shared contracts to companies having EOR expertise or knowledge of how to use the techniques.

The Little Tom thermal recovery project was the first thermal EOR cost-shared contract awarded by ERDA in January 1975 under this program. The objective of this cost-shared demonstration project was to demonstrate the economic recoverability of low gravity, viscous oil from a relatively thin, low-permeability, Texas heavy oil reservoir using in situ combustion (ISC) process. Since the oil is too viscous to produce at the rate it was expected to be displaced by the combustion front, it was also proposed to thermally stimulate the producers to realize productivity improvements, prior to heat breakthrough.

Operating under ERDA contract, the Hanover Petroleum Corporation conducted the project in the San Miguel sand of Little Tom field, Zavala County, TX. The Little Tom field is located in the west central part of the county about 6 miles west of the town of La Pryor. Geologically, the field is in the Rio Grande embayment where oil production is found in a number of sands of Upper Cretaceous Age. The Hanover portion of the Little Tom field encompasses some 3,520 acres and is estimated to hold about 40 million barrels of 14° API oil in the San Miguel A, A-1, B and C sands at a depth of about 2,800 ft. Total oil saturated sand thickness in the project area averaged 40 ft. The pertinent reservoir and fluid characteristics are presented in Table 5.

The ERDA-Hanover Petroleum agreement called for the implementation of the project in four stages with an option to terminate the project at the completion of a phase based on technical and economic consideration. The four phases were:

Phase I	Thermal stimulation (short-term in situ combustion at the producing well) of producers to improve productivity and to establish formation air injectivity
Phase II	Well drilling and project development
Phase III	Project operation
Phase IV	Final performance evaluation and project expansion

A successful method of oil recovery at Little Tom combustion project required the producing wells be stimulated prior to the arrival of heatfront. Hanover Petroleum, as part of its Phase I operation, chose to stimulate the producers by a cyclic in situ combustion process, as it was thought to be thermally more efficient than steam stimulation in improving well productivity. Further, the process was also thought to establish the air injectivity of the formation.

During Phase I, thermal stimulation operations were conducted on two producing wells, Nos. 8 and 9. Three concerted efforts were made to ignite and initiate thermal stimulation experiment on well No. 9. Of the three efforts, only the first one successfully achieved ignition of the downhole burner for the desired length of time. Formation ignition during this attempt was indicated by the low oxygen content of gases subsequently produced from well No. 9. However, very little carbon dioxide was found in the samples, indicating reaction within the formation was probably a low temperature oxidation reaction. Breakdown of the air compressor and subsequent wellhead failure prematurely aborted the first ignition attempt. Prior to the second ignition attempt, the heat shield was hung about 47 feet lower than its previous position. It was thought that by reducing the length of the hole to be heated by the gas burner, that the chances for achieving ignition in the formation at the lower injection rate associated with this well could be enhanced. However, a sudden pressure surge, resulting from wellbore air leak, broke the wireline carrying ignition chemical, leaving the wireline ignition tool in the tubing.

The wireline ignition tool was recovered and the leak sealed. A third and final attempt was made to ignite the well. Though the ignition was achieved, the desired injection rate could not be maintained without exceeding the compressor design pressure and formation frac pressure. Efforts to stimulate well No. 9 were terminated, because of excessive pressure and probable casing damage.

Well No. 8 was selected for the next thermal stimulation effort. The first ignition attempt was successful, but the burner was unintentionally extinguished after six hours because of a momentary, but abrupt, change in air rate at the compressor. The burner was reignited, but the operation could not be prolonged due to repeated compressor failure and a general deterioration in air injectivity because of tubing damage near the heat shield.

In view of the repeated ignition failures and the resulting high operating costs, the project was terminated at the end of Phase I work.

Paris Valley Combination Thermal Drive (1975–79)[6]

Husky Oil Company, with the support from U.S. DOE (then ERDA), initiated a wet in situ combustion pilot, augmented with cyclic steam stimulation, within the Paris Valley field, Monterey County, CA, in March 1975. The purpose of this test was to assess the technical and economic feasibility of these thermal recovery techniques within an unconsolidated sandstone reservoir that never produced economic quantities of oil due to the very viscous nature of the crude. This was the second thermal EOR cost-shared contract awarded by ERDA under the ERDA's EOR Program.

Wet combustion, in lieu of other thermal techniques, was selected as the oil recovery process in Paris Valley field, because it was thought the heterogeneous permeability profile would permit heat to breakthrough to the producers and improve the vertical sweep while the well produces at an elevated temperature. Also, to match the production with displacement prior to the heat breakthrough, stimulation of producers by steam was proposed.

The pilot site was in the southwest part of the Paris Valley field in T21S-R9E, Monterey County, CA, about 160 miles south of San Francisco. Geologically, the Paris Valley field consists of unconsolidated, oil bearing miocene sands that were deposited along the ancient shoreline of the Salinas basin—commonly referred to as the Gabilan shelf. The pilot was in the Ansberry sand, which is found at an average depth of 800 ft from the surface. The Ansberry sand is separated into three distinct zones, referred to as the Upper, Middle, and Lower Lobes. The Middle Lobe is thin and contained insignificant amounts of oil. The total net oil sand thickness in the pilot area varies from 4 ft to 84 ft, while Upper Lobe net oil sand thickness varies from 4 ft to 24 ft and the Lower Lobe from 9 ft to 58 ft.

As indicated in Figure 4, the pilot was designed to operate in five staggered linedrive patterns. Eighteen producers and five air injection wells were drilled in the pilot area. Nine wells (1, 8, 9, 10, 12, 13, 15, 16, and 18) were completed in the Upper Lobe, six were completed in the Lower Lobe, and eight wells in the full interval of the Ansberry sand, including the Upper, Middle, and Lower Lobes. The air injectors were completed down-dip from the center of each pattern in an effort to compensate for the expected directional flow of air up-dip. Two temperature observation wells were also drilled for monitoring and data gathering. All the wells were cored and logged to characterize the formation. The core materials from Well 3 were utilized to evaluate the combustion characteristics of the Ansberry sand. The pertinent reservoir and combustion characteristics are presented in Table 6.

Initial combustion test was initiated in January 1976 using a rental compressor, due to operational problem with the main compressor equipment. The initial testing was concluded in September 1976 after injecting 60 MMscf of air. The purpose of the test was to establish the formation air injectivity and to determine the air injection rate. The first well was ignited utilizing a downhole gas burner, which was set immediately above the perforation. The use of downhole burner was, however, discontinued in later ignition operation because it was found that the formation could be autoignited by injecting steam to supply the heat requirement for ignition.

After completing several repairs to the main compressor air injection was resumed in May 1977 in Wells 6, 8, 12, 15, and 18. It became quickly apparent that the injectivities in wells completed in the Upper Lobe were significantly lower than Well 6, completed in the Lower Lobe. Air injection and burning appeared to have been retained in the Lower Lobe of the Ansberry sand. Leading edge of the heat zone reached updip wells completed in the Lower Lobe, but did not reach the upstructure wells. High injection pressure became necessary to inject air into the Upper Lobe, which contained the most viscous oil. High injection pressure resulted in severe channeling of air upstructure into Well 21. Air injection was halted in August 1977 due to first stage piston failure. After repairing the compressor, air injection was resumed in January 1978 in Wells 6, 12, 15, and 22. Air injection into Well 18 was discontinued due to mechanical problems with the surrounding wells. Air injection was terminated in February 1979, due to operations problems.

Well 21 was the only well that produced incremental oil from combustion operation. After heat broke through in the well, a cooling system was installed in the well to prevent the bottomhole temperature from exceeding 350° F. However, failure of the cooling pump caused the bottomhole temperatures in Well 21 to exceed 700° F and damaged the liner. Attempts to replace the damaged liner were unsuccessful and eliminated any further chance of producing the well. Heat also broke through in several other wells (Nos. 4, 11, 14, and 17), but combustion gas and high water production prevented these wells from being kept pumped off and producing the oil.

Only 61% of the injected air was recovered in the producing wells. The balance was probably flowed outside the pilot area. Tracer tests indicated the migration of unrecovered air outside the pilot area. Significantly high operating costs were incurred during the operation of the pilot. The electric power costs for air compression increased by 233%. Required well work was impeded by high casing pressure in the producing wells. Damage to producing wells from severe channeling of the combustion gas resulted in expensive workovers. Oil production rates were not sufficient to offset the high operating costs and continue the project. In view of the problem prone operations and poor oil production, the pilot was terminated in March 1979 as uneconomical. The total operating costs for the pilot were $3.317 million or $23.89/bbl. The pilot did not generate any profit at 1978 oil price of $24/bbl.

Bodcau In Situ Combustion Project (1976–82)[7,8]

The Bodcau fireflood was the only DOE-industry cost-shared in situ combustion project that was both technically and economically successful. In 1971, Cities Service began a pilot combustion test in the Bellevue Field, located in northwestern Louisiana, which was later expanded to a leasewide operation. The success of this in situ combustion project prompted Cities Service Company to enter into a cost-sharing contract with the U.S. Department of Energy (then ERDA) to demonstrate the efficiency and economics of a commercial scale wet in situ combustion process and to test techniques for increasing vertical sweep efficiency while reducing overall project time.

The Bodcau in situ combustion project was conducted in the Bellevue Field, located about 18 miles northeast of Shreveport, LA, on the eastern edge of Bossier Parish. The demonstration site, located in the southwest quarter of Section 11-T19N-R11W was part of Cities Service Oil Company's (now OXY-USA) Bodcau Fee B lease. The Upper Cretaceous Nacatoch sand, found at 400 ft depth, is the main producing sand in the field. The demonstration site was selected based on the data from five evaluation wells. The log and core data obtained from these wells were utilized in mapping the structure and pay thickness, as well as in determining the pattern size and configuration. The patterns were about 4 acres in size and arranged in an elongated inverted nine-spot. The injection well was located down-structure to compensate for the movement of air up-structure. The patterns were elongated up-structure to provide for optimum sweep efficiency in the patterns. Five patterns were developed due east of Cities' original fireflood project and are shown in Figure 5. The reservoir and fluid characteristics are shown in Table 7.

Following extensive laboratory combustion tube experiments, the five injectors were ignited using electric heaters in August and September of 1976. During the first six months of operation, air was injected down the casing for the dry burn phase. After the injection rates stabilized at their maximum, the injectors were reperforated in the top 10 to 12 feet to allow water injection into the upper section of the Nacatoch sand simultaneously with air injection into the base of the zone. A limestone interval provided partial separation of the two injected fluids. The purpose of water injection was to improve vertical sweep efficiency by forcing the combustion to expand farther out in the lower section of the reservoir before rising to the top, thereby heating a larger volume of the reservoir.

During the combustion phase, the producing wells experienced hot gas breakthrough or even burnout as combustion front approached the producers. When this occurred, the wells became impossible to operate due to sand production problems or tubing leaks resulting from the blowtorch effect of hot gases on the tubing. When a producing well became difficult to operate, the tubing was pulled, and the depths of the markings on the tubing were noted as an indication of the interval through which the sand laden hot gasses were flowing. The producing interval was squeeze cemented, and only the sections not causing the well problems were reopened for production. This process was repeated several times during the combustion phase.

In spite of considerable care in design and operation, an explosion occurred in the air compression/injection system, destroying the distribution lines and severely damaging one compressor. Buildup of a lubricant film on the inside walls of the air injection line was determined as being the cause of the explosion. The distribution lines were repaired and put back into service within 36 hours, and preventive actions such as periodic washing of the air distribution system with 5% nitrox solution (mixture of sodium hydroxide and sodium nitrite) and careful checks of lubricants on discharge valves and cylinders for buildup during maintenance, were taken to prevent future explosions.

Air injection was terminated in late 1980 after 50% of the pattern volume was burned and heat scavenging water injection was initiated. Because of the gravity segregation effects, much of the heated oil remained in the lower portion of the thicker pay after the termination of air injection. This heated oil was displaced and recovered by the heat scavenging water.

During the six years of operation (duration of the DOE contract), the project produced 667,609 bbl of oil, compared with 700,000 bbl predicted. It was anticipated that the project would ultimately produce more than the predicted 700,000 bbl of oil, if the economics permitted it. Whether this was the case is not known, because no project-related production data were released since the expiration of the DOE contract in 1982.

The project paid out and yielded attractive economics under the economic climate in which it was conducted. During the DOE contract period the actual expenditures were $8.79 million compared to the initial estimated expenditure of $8.23 million. Additional work beyond the initial scope of work for the project, including drilling nine additional producing wells and four postburn core wells and also repairing the damaged compressor, added to the unplanned costs.

Lynch Canyon Thermal Driver Project (1978–80)[9]

This was a proposed project by General Crude (GC) to demonstrate and evaluate the recovery of a highly viscous crude oil using a modified in situ combustion process known as the Combination Thermal Drive process. This process involves simultaneous injection of air and water to burn and displace the oil through the formation and steam stimulate the producers to match the production with displacement.

The test was initiated in the highly permeable Lanigan sand of the Lynch Canyon oil field in Section 24, T22S-R10E, Monterey County, CA; approximately 30 miles north of the town of Paso Robles. The southern boundary of the field is adjacent to the northern boundary of the San Ardo field, the site of one of the highly successful steamflood operations in the U.S.

The project site encompassed approximately 60 acres. The field encompasses 400 acres, and the oil volume at the project site was estimated to be 26 million bbl prior to the beginning of the project. Texaco, the early owner of the field, developed about 175 acres in the center of the field, but did not include the southern portion of the field, the project site. Texaco produced the field during 1963–65 by cyclic steam operation, but discontinued the program due to frequent casing failures and production problems. Texaco relinquished the ownership in 1968.

GC, who felt that with the advances in thermal completion technology, the field could be developed economically, assumed the ownership in 1972 and submitted a proposal in 1977 to ERDA, predecessor of DOE, to demonstrate the applicability of a novel thermal method to produce viscous crude from highly permeable sands. General Crude's proposal called for the demonstration of combination thermal drive process, a modified in situ combustion process that purported to achieve a high displacement efficiency by simultaneous injection of air and water and improve recovery by matching production to displacement.

Mobil Oil Corporation acquired GC in 1978 and formed Mobil-GC Corporation to implement the project. Mobil-GC entered into a contract with DOE in 1978 to demonstrate the applicability of the process in Lynch Canyon field, a typical California heavy oil field. The DOE-Mobil-GC agreement called for the implementation of the project in four stages with a decision point built-in at the end of each stage to continue or discontinue the project based on progress review. The four stages were:

Phase I	Geologic and reservoir evaluation
Phase II	Pilot testing and project development
Phase III	Well drilling and operation
Phase IV	Final evaluation of performance

Reservoir and fluid properties of the project site were not known prior to the completion of Phase I activities. General Crude developed the project plans, using best available reservoir parameters. These properties (Table 8) were derived using Texaco's log and core analysis data of the Lynch Canyon field. The basic objective of Phase I operation was to drill and log wells at the project site to thoroughly evaluate the reservoir characteristics of the project area

Four wells were drilled and cored during the Phase I operation (see Fig. 6), and the cores were analyzed for porosities, permeabilities, fluid saturations, and combustion characteristics of the formation.

After analyzing the results for Phase I, several factors became evident, which were unknown at the initiation of the project. These included a lower oil saturation than previously estimated (1,800 STB/ac-ft as opposed to the initial estimate of 2,080 STB/ac-ft), increased drilling costs due to the overlying high-pressure water sands, increased investments due to changes in environmental permit requirements and an oil viscosity eight times higher than anticipated. Table 9 summarizes the comparison of reservoir and fluid properties prior to the beginning of the project with those obtained after the completion of Phase I activities.

Due to significant changes in critical reservoir parameters and their effect upon the project economics, Mobil terminated the project with DOE's approval.

Bartlett In Situ Combustion Experiment (1978–81)[10]

As part of its in-house research program on EOR, DOE's Bartlesville (OK) Energy Technology Center (BETC) conducted a small in situ combustion test in a shallow Bartlesville sand reservoir. The objective of this field experiment was to evaluate the technical feasibility of the in situ combustion in a shallow, low-permeability, Midcontinent heavy oil reservoir and to develop guidelines for conducting in situ combustion tests in such reservoirs. The site selected for the experiment was the Link Lease in Labette County, near Bartlett, KS. The reservoir and fluid characteristics at the test site are shown in Table 10.

The site area for the experimentation encompassed 5 acres. Well 1 was drilled in December 1977 to establish a 1.25-acre inverted five-spot pattern with Wells 2, 3, 4, and 5 as producers (see Fig. 7). Air was injected into the central injection well to determine the extent of communication between the injector and producers. Since no communication was found to exist, the communication between the injector and the producers were established by hydraulically fracturing the formation between the injection well and the four producers.

Two attempts were made to ignite the 15° API gravity oil in the Bartlesville sand. The first attempt was made in September 1978 using an electrical ignition system. The heater was rated at 1.75 MM Btu/D at full power. Air flowing over the heater carried the heat into the reservoir. The rate of air flow was controlled at 150 Mcf/D, sufficient to provide a temperature of about 1,042° F at the perforation. The heater was left in place for six days to ensure ignition.

After six days of heating, data to determine the success of ignition and progress of burn were obtained from temperature logs from the injection and production wells and gas analyses for CO_2 and O_2 content from production wells. Temperature readings obtained from the production wells during the first six months showed no change in formation temperature, indicating absence of fire in the formation. The produced gas analysis indicated the presence of a burn during the early months of ignition, but later analysis showed no presence of CO_2. It was concluded that the first ignition attempt failed to sustain combustion in the formation.

A tracer test was performed to determine the flow direction for the injected air. The test indicated an east-west flow direction with majority of the tracer being produced from an old unplugged abandoned well approximately one-fourth mile northeast of the injector. Thus, it was concluded that a major portion of the injected air was vented through unplugged wells and the air reaching the firefront was inadequate to sustain the combustion front.

In August 1979, a squeeze cement job was performed in the injector to close the existing perforation and the well reperforated at a lower depth. Simultaneously, the producers were hydraulically fractured and chemically stimulated to establish better communications with the injector.

A second ignition attempt was made in September 1979. Temperature survey indicated a small rise in temperature for two months, but the fire was put out due to compressor failure. A new compressor was installed and the attempt to reignite the formation was unsuccessful. Tracer tests indicated that much of the air was leaking beyond the pattern through fractures created by producer frac job and escaped out of old unplugged wells. The experiment was terminated in July 1980, due to leaks through unplugged wells and ignition failures.

PROJECT EVALUATION AND DISCUSSION

Appalachian Area In Situ Combustion Projects

All three in situ combustion experimental field tests carried out by USBM in the Appalachian area reservoirs were unsuccessful and failed to recover any significant additional oil. There was no conclusive evidence from injection and production data that self-sustained combustion was achieved or that combustion was responsible for increasing oil and water production. A slight oil production increase was attributed to stripping of light oil by the air injected at rates which were higher than those normally used during the air-gas repressurization operation. Post test core analysis gave no indication of the formation of any liquid banks in the reservoir. Based on post test data analysis, USBM cited lack of sufficient fuel near the ignition well as the principal reason for project failure. They speculated that high air injection rates and temperature during the ignition period of each tests probably reduced the oil saturation in the vicinity of the ignition wellbore below the minimum required (0.3) to support a self-sustaining combustion front.

An examination of the reservoir, fluid and project data presented in the project reports,[1–4] however, provided ample evidence as to why these projects failed. Several reasons can be given for the lack of success on low oxygen utilization and inability to support a self-sustaining combustion front. The reservoirs were highly heterogeneous, resulting in severe channeling of the air through high-permeability streaks, causing fluids to be produced from wells outside the project area. Sufficient volume of air was not reaching the low-permeability, high-oil saturation regions to sustain and advance the combustion front. Poor combustion could also be attributed to properties of the Appalachian crude and/or low-oil saturation. The distillation characteristics of these crudes indicated that these crudes in general are highly volatile, and over 69% vaporizes below 570° F, leaving approximately 31% as residuum. This would have resulted in the vaporization of most of the oil near the injection wellbore during the ignition attempt, leaving very little fuel for combustion. This shortcoming was realized in later tests, and attempts were made to rectify the situation by injecting low gravity Midcontinent asphaltic base crude to increase the oil saturation around ignition wellbore. Though this permitted the ignition of the formation, further away from the injection well fuel deposition was insufficient to sustain and propagate the combustion. Postburn core recovery indicated that only about 15 ft of formation was burned and shale streaks acted as barriers to combustion front propagation.

In situ combustion was successful in recovering oil in other high gravity waterflooded reservoirs (non-DOE funded projects) such as the May-Libby field in Louisiana[17] and Delaware-Childers field in Oklahoma.[20] These projects were also carried out during the same time period as the Appalachian area firefloods. In Table 11, the reservoir and fluid characteristics of these successful high gravity oil fireflood projects were compared with those of the failed projects. The common elements among the successful projects are reasonably clean sand with high porosity sand containing a less volatile crude. In Table 12, the distillation characteristics of the crude from second Venango sand (a 36.2° API oil) are compared with those of May-Libby crude (a 40° API oil). It is clear from this comparison, even a low gravity Appalachian crude is more volatile than a high-gravity nonparaffinic crude.

To summarize, the reason for the failure of Appalachian area combustion projects could be attributed to poor site selection resulting from a lack of thorough study of past data that apply to pilot project area. In situ combustion is not likely to be successful in Appalachian area because of the very low oil saturation, high oil volatility, and cost of locating and plugging old, improperly plugged and abandoned wells.

Little Tom Thermal Recovery Project

In situ combustion is an expensive operation and profitable producing rates are needed to support the project. The low transmissibility of the Little Tom field in San Miguel sands was not conducive to the economic production rates without the support of some kind of effective stimulation. During Phase I, thermal stimulation operations were conducted in two producing wells to improve productivity, but proved to be unsuccessful. Gas analysis data indicated that low-temperature oxidation occurred, but a high temperature burn zone was never established. Thermal treatment (cyclic in situ combustion of the wells) did not improve oil production rates, and casing was damaged in both wells.

Injection pressures as high as 2,300 psig were experienced. It was found that unless the effective air permeability was greatly increased after flow was established to the producing wells, air injection to support in situ combustion would require injection pressures greater than the overburden pressure in the Little Tom field.

Fluid injectivity and production tests on several wells in the pilot area indicated that most, if not all, of the oil production from these wells had come from San Miguel B zone, only one of the four zones, targeted for in situ combustion. The other three target zones, though perforated and potentially productive in all wells, took very little air and proved to be unproductive. Since the investments required to fireflood only one zone would not be significantly less than that required to fireflood all four zones sequentially, project became economically unattractive.

The oil produced from B zone was of much lower gravity and higher viscosity than originally estimated. The viscosity of the produced crude was too high to permit reasonable production rates, even if thermally stimulated. From the onset, the project was fraught with frequent injection equipment failures and high maintenance costs, and this escalated the operating costs beyond the budgeted values.

Several reasons can be cited as to why the in situ combustion process failed in Little Tom field, while the process was economically successful in another south Texas heavy oil field. Poor combustion characteristics of the crude and low reservoir permeability are the principal reasons why the project failed. It appears that less importance was attached to the combustion tube results. These data clearly indicate that the oil is difficult to burn and requires about 400 scf/ft^3, compared to average air requirement of about 220 scf/ft^3 in successful projects. This high air requirement is an indication of high compression costs. The low permeability of reservoir prevented the air being injected at the desired rate without exceeding the formation fracture pressure. The lower injectivity resulted in lower air fluxes and poor combustion characteristics. Attempts to increase the air injection rate caused the injection pressure to exceed the 2,000 psig compressor design rating and led to frequent compressor failure and high repair costs.

Thermal treatment of a production well in a viscous oil formation depends upon the amount of heat to be released. Given the thermal treatment desired, the basic combustion parameters and air injection rate required to achieve the desired treatment can be calculated. Based on the combustion characteristics of the crude calculations indicate that to achieve economic oil production rate by thermal treatment, the air requirement must exceed 500 Scf/ft^3. Since it was not feasible to attain this value in this field, all thermal stimulation attempts failed.

In Table 13, the reservoir fluid and combustion characteristics of Little Tom field are compared with the characteristics of other successful south Texas firefloods. Analysis of those data indicate that the common characteristics among the successful projects include high-permeability, high initial oil saturation, low air requirements and lower fuel requirements. Detailed case history of these successful south Texas firefloods appeared in the literature in early 1970s. A thorough study of these case studies, in conjunction with the field geology and combustion tube results should have indicated that the proposed area and/or formation is not suitable for the application of fireflooding.

Paris Valley Combination Thermal Drive

In spite of possessing many of the desirable attributes (thicker pay, high oil saturation, high permeability and porosity) that one would like to see in a candidate reservoir for combustion, the Paris Valley combustion project was unsuccessful and failed to produce significant incremental oil. While there are several interrelated reasons for failure, two factors adversely affected the project performance: (1) high oil viscosity in the Upper Lobe and (2) operational problems resulting from poor planning. The vast difference that existed in the viscosity of oil produced from the Upper and Lower Lobe had a very significant effect on the project performance. The Upper Lobe produced an oil that was ten times as viscous as that from the Lower Lobe. The viscous oil in the Upper Lobe caused a viscous oil block to form and much higher air injection pressure was needed than for the lower viscosity Lower Lobe. This resulted in a pressure gradient sufficient to allow the injected air to break into the Lower Lobe. This channeling of air into the Lower Lobe caused much of the injected air to bypass the upper zone and starve the Upper Lobe combustion front of oxygen. Combustion front stalling appeared to occur as characterized by a low static temperature profile in the Upper Lobe.

The maximum observed temperature in the observation wells completed in the Upper Lobe never exceeded 500° F indicating the occurrence of low temperature oxidation (LTO) reactions. Since this temperature was within the negative temperature gradient range reported by Moore et al.,[11,12] it is suspected that the failure of the reaction temperature to transcend the negative temperature gradient region could partly explain the poor oil recovery from the Upper Lobe. Air injection into the Lower Lobe was no problem and the lower zone exhibited good burning characteristics as evidenced by high observation well temperature (greater than 750° F). However, the channeling of air from the Upper Lobe into the Lower Lobe affected efficiency of downhole pumps in the Lower Lobe.

Frequent compressor failures also hastened the demise of the project. When air injection was interrupted due to compressor failure, backflow occurs. Due to the unconsolidated nature of the formation, the backflow resulted in severe sanding at the injection wells and costly workover. Further, when air injection was interrupted, vertical drainage resaturated the burned zones. This resaturated rock was hot and must be burned again before the burning front can proceed. This increased the overall air requirement of the project. In at least one instant, the backflow of the combustion gases into an injection well resulted in an explosive mixture and damaging detonation when air injection resumed.

In the final analysis, the project failed due to poor selection of test site and planning. The combustion tube tests indicated an air-oil ratio (AOR) requirement of 18.2 MScf/bbl that was above the values reported for the economically successful fireflood projects. Burger[23] suggested that as a general rule, for both technical and economic success, the AOR should be below 18 Mscf/bbl. Electric log and core analysis of the project wells gave reliable results for porosity, permeability, and oil saturation, but did not indicate the vast difference in the viscosity of oil produced from the Upper and Lower Lobe. A production test from a well open to both zones was used for the productivity calculation and average viscosity. The result was very misleading, and the project was designed based on this information. This resulted in the purchase of an undersized compressor, which later proved to be totally inadequate for delivering air at the desired injection pressure. The situation could have been avoided, had each zone been tested separately and oil viscosity from individual zones determined prior to the design of the project.

While the effective permeability in both zones were almost equal, injectivities were widely different. This was not recognized during the planning and design stage. The viscous oil in the Upper Lobe caused a viscous oil block to form which necessitated a much higher air injection pressure that exceeded the compressor design pressure. Each zone should have been tested separately by an extended air injection tests, prior to committing to the project.

The reservoir structure that was assumed for the Paris Valley Project was later determined to be incorrect. While it was assumed that injection was in the down-structure wells, in actuality these were in the wrong side of a syncline. This resulted in migration of air and combustion front away from the pattern. The situation could have been avoided, had some wells outside the project area been included in the analysis to determine the reservoir structure, even if it required drilling additional wells.

To minimize project capital costs, no backup system was included for the surface facility, such as a cooling water pump. Mechanical failure of the cooling water pump resulted in the loss of a producer with heat breakthrough. It is prudent to have a backup for critical equipment.

Bodcau In Situ Combustion Project

The Bodcau in situ combustion project was the only DOE cost-shared in situ combustion project that was carried to completion and resulted in oil production close to the predicted values.

The project was carefully designed (which cannot be over-emphasized) and well operated. Many of the operating problems were predicted and backup provided. Due to the extremely low reservoir pressure (40 psig), it became necessary to operate the producing wells at minimum possible bottomhole pressure to maximize pattern oil recovery. This operating procedure required that a static liquid level be maintained below the producing formation at all times. This was accomplished by setting subsurface pumps at a total depth and keeping the well continually pumped off. This was also necessary to minimize sand production. The operator installed a gas collection system to control the venting of hot produced gases and maintain the bottomhole pressure at the desired value. The extreme downhole temperature and the velocity of the gas caused condensed water to float inside the casing just above the high temperature zone. This resulted in pressure buildup and fluid production stoppage. The problem was solved by periodic cycling of vented gas from zero to maximum flow. This cycling allowed the condensed water to drop to the bottom of the well, where it was removed by the subsurface pump, reducing bottomhole pressure and also partially cooling the hot section. Hardened and honed pump barrels were utilized to minimize pump erosion due to sand production. Pressurized heater treaters were used to break emulsions and lower bottom sediment and water (BS&W). Coke buildup in the casing/tubing annulus was minimized by periodic cleaning. In spite of a well-planned operation, an explosion occurred in the air injection system, destroying the distribution lines and severely damaging one of the three main compressors. The explosion was attributed to the buildup of a lubricant film on the inside walls of the air injection lines.

In spite of all the efforts to minimize sanding problems, sand production and the handling of hot combustion gases remained the major operating problems during project life. Of the eight original producing wells, only the one farthest from the injector did not require remedial work. Remedial cement squeeze jobs were performed in producers at frequent intervals to shut off perforations at which hot combustion gases carrying sand eroded the perforations. Remedial work at wells along the north line of the project area became so frequent and difficult that these wells were shut off and not returned to producing status until long after the termination of air injection in October 1980.

To better evaluate the performance of the simultaneous air and water combustion process, four wells were drilled, cored and logged. Results of the program indicated extensive burning outside of the pattern area. Based on the interpretation of the core and log results, Cities Services arrived at the following conclusions:[13,14]

(1) The geologic structure played a significant role. Air preferentially migrated up structure while water moved down, causing variations in the in situ combustion process ranging from dry to quenched combustion at various positions.

(2) Several hard lime streaks kept of the injected fluids separated behind the leading edge of the waterflood. Ahead of the water, they did not impede the migration of air to the very top of the zone.

(3) Residual oil saturation in the burned intervals was zero, indicating a highly efficient process.

(4) Significant reductions in oil saturation down-dip of the injector, in intervals above the hard lime streak, was an indication of quenched combustion or hot waterflood. Based on the analysis of clay alterations, quenched combustion was surmised.

(5) The simultaneous air and water injection process with partial vertical separation is not ideally suited to reservoirs with appreciable structure when applied in a pattern type development.

In summary, the Bodcau in situ combustion project was both technically and economically successful, paying out quickly, and provided an attractive return on the invested capital. The capture efficiency, however, was low. Though 72% of the oil in place was displaced, only 42% was captured. Extensive migration of oil outside the lease line occurred as a result of excessive air injection. The operator should be commended for having devoted considerable effort to the design and operation of the project and for thoroughly documenting the project operations. The project performance indicates that very little was left to chance, and that virtually all difficulties were foreseen and every effort made to deal with them.

Since the oil recovery was close to the forecasted level and the project costs were close to the projected amount, it is clear that the operator fulfilled the set objective and demonstrated that a carefully designed and well-engineered combustion project can overcome technical obstacles and will result in economic success.

Lynch Canyon Thermal Drive Project

The Lynch Canyon combustion project is a good example of how careful attention to the geological conditions of the project site and recognition of undesirable characteristics of the crude before the start of the in situ combustion project led to the decision not to proceed beyond Phase I.

During the Phase I of the project, four wells were drilled and cored to evaluate the geology of the project site. In addition, laboratory combustion tube runs were made using core material from the Lynch Canyon project site. The results revealed several factors which were unknown at the initiation of the project.

Core analysis indicated a lower quantity of oil in place and a substantially higher water-oil ratio, which reduced the productive limits of the field. Further, the fluid analysis revealed the viscosity of the in situ crude to be eight times higher than those reported by the previous operator of the field. Phase I drilling also revealed the existence of a high-pressure aquifer above the producing interval, which pointed to a likely operation problem. Further, the combustion tube results indicated that the combustion front is not sustainable without the injection of very large air volumes. Since all of the preproject evaluation pointed to a dismal operation and poor economics, a decision was made not to implement the project.

It is considerably more difficult to implement and operate a combustion project in highly viscous oil reservoirs. Oil mobility is a critical factor governing the success of the combustion process in such reservoirs. In Table 14, the reservoir and fluid properties of Lynch Canyon field are compared with the nearby Paris Valley field, also a very heavy oil reservoir. The DOE cost-shared in situ combustion project in the Paris Valley field experienced considerable reservoir and operational problems and was ultimately terminated. Failure of the Paris Valley field combustion project was due to operational difficulties and played a major part in Mobil-GC's decision not to pursue the Lynch Canyon combustion project. Mobil-GC should be commended for learning from other's experience and for not going ahead with a project that had very little chance for success.

Bartlett In Situ Combustion Experiment

Interest in the application of combustion technique to recover the low gravity crudes in the Bartlesville sandstone dates back to the mid-1950s. At least a dozen combustion projects were implemented in this sand in the 1950s and 1960s. These projects, along with their pertinent reservoir and fluid data, are detailed in Table 15. All but four were failures. All of the failed projects were implemented by small operators who had no previous thermal experience. Poor planning and underfinancing were cited as the principal causes for failure. The successful ones were implemented by majors and knowledgeable independents. These projects succeeded because they were well financed and implemented in carefully selected sites by operators with considerable experience in implementing combustion projects. These operators expended considerable effort towards planning, design, and operation of the project. Well-documented case histories of these projects have appeared in the petroleum engineering literature. In spite of these well-publicized success stories, interest in the application of thermal techniques to recover heavy oil waned among Midcontinent independents due to excessive number of failures.

To revive interest in thermal operations among the Midcontinent operators and to encourage them to take a second look at the technology, the U.S. Department of Energy, through its Bartlesville Energy Technology Center initiated a small field test in a Bartlesville sandstone. This in-house experimental field test was designed and implemented by the DOE staff on a 1.25-acre site on the Link lease in Labette County, KS. The test recovered an insignificant amount of oil (810 bbl) at an excessively high air-oil ratio (330 Mscf/bbl).

The reasons for failure of this experimental fireflood project can be attributed to a lack of thorough study of past records as well as to poor planning and engineering. The selected fireflood project location was the site of an earlier aborted fireflood project. A fireflood was attempted in 1961 by Collins Oil Company in the Link lease,[15] but the project was terminated for reasons unknown. A thorough study of past records would have revealed the previous operation in the área. Old unplugged wells with locations unknown were another main factor that caused the project to fail. Large volumes of injected air migrated to and escaped from unplugged wells. This excessive diversion of air from the combustion front starved the combustion process of needed oxygen and resulted in low temperature burn and poor oil mobilization.

No systematic combustion tube tests were conducted on cores recovered from the Link lease to establish air requirements and fuel consumption, as well as other operating parameters. Instead, tube runs were made, utilizing clean quartz sand and reservoir crude to ascertain the combustibility of Link lease crude. The operating parameters were determined using published empirical correlations. Based on these correlations, the project air requirement was determined and a compressor capable of delivering 500 Mscf/D at 350 psi was specified. However, this compressor capacity proved to be totally inadequate to meet the project air requirements. Such factors as anisotropic characteristics of the reservoir, fractures zones, and the existence of undocumented unplugged wells at the project site caused the project daily air requirements to exceed the available capacity by several orders. Poor compressor maintenance resulted in frequent compressor failure and loss of air injection during crucial periods of time.

In Table 16, the Bartlett combustion project reservoir and fluid properties are compared with other successful Bartlesville sand in situ combustion projects. This table shows that both the failed and successful projects possess almost identical characteristics, an indication that the in situ combustion process can be successfully implemented in the Bartlesville sand. The exploitation of oil reservoirs in the Bartlesville sand by combustion process, however, will require careful planning. Due to anisotropic characteristics of the Bartlesville sand, stream tube model studies must be conducted to establish flow direction and the pattern designed to accommodate the anisotropic distribution of air flow. A good example of such a design is the Sun Oil Company's Iola Fireflood.[16] Previous producing practices should be seriously considered when designing the project to ensure success. Prior to implementing the project, every effort should be made to locate the abandoned wells through tracer tests or pressure tests and the wells plugged to minimize air leaks and project air requirements.

LESSONS LEARNED

From the review of the DOE-industry in situ combustion projects, it became apparent that projects such as the Appalachian area in situ combustion tests had a remote chance for success at the chosen site and should not have been initiated. Several other failed projects would have fared better had more attention been paid to project planning activities and engineering design. This review indicated that many factors influence the outcome of a project which, if properly understood, can improve the probability of success of a project. Some of these factors and the role they played in the outcome of the reviewed project are summarized in the following comments.

The most important factor that must be considered prior to undertaking a combustion project is to ensure that the geology of the site will favor the process. A nonfractured and relatively clean sand with a relatively low oil saturation is preferable to a highly heterogeneous sand with high oil saturation. In a geologically complex area, a few exploratory wells must be drilled, cored and logged to confirm the geology and reservoir properties before deciding whether to proceed with the project. In the case of the Paris Valley combustion project, failure to confirm the geology and reservoir properties through drilling exploratory wells resulted in the locating injectors on the wrong side of a syncline. This resulted in the migration of air and combustion front away from the pattern and eventual demise of the project. The Lynch Canyon fireflood operator, however, was aware of the importance of confirming the geology at the project site, drilled a few key wells and obtained core and fluid data. These data revealed potential problems (less than anticipated oil volume and a highly viscous crude) that led to the decision not to proceed with the project.

Second, the importance of good planning and proper site selection and its effect on project success should not be overlooked. Poor planning and improper site selection were among the reasons the Little Tom and Bartlett in situ combustion projects were doomed. In the case of Little Tom Field fireflood, the selected site was so remote that considerable expenses were incurred in developing infrastructure, such as laying pipelines to secure reliable gas supply for compressor operations and in building all-weather access roads. Since a great percent of the project fund was expended in developing the infrastructure, and surface facilities, very little funds were available to undertake preliminary work such as drilling of key exploratory wells to confirm the geology and reservoir properties. The operator based his project design upon the existing geological and reservoir information that later proved to be incorrect. While it was assumed that all sands were in communication and reasonably permeable, actually the air entry into the formation was limited to only one sand of limited permeability. The location of the project site was so remote from the source of oilfield supplies, services and equipment that delays up to two months were experienced in obtaining services. This greatly affected the project. In the case of Bartlett project, failure to confirm the reservoir properties before finalizing project site, led to the selection of a location that was highly anisotropic and resulted in the migration of large amounts of air outside the pattern and starved the burnfront of much needed oxygen. Realization of this characteristic a priori could have resulted in a design to minimize air loss to outside the project area.

The third point that needs emphasis is the importance of thorough examination of past records, as well as the published case histories of combustion projects implemented in similar reservoir settings. A considerable data bank of experience exists in open literature and should be used to formulate plans and decisions. Careful review of case histories can shed light on potential problems and help avoid costly mistakes. A case in point is the Bartlett (KS) in situ combustion experiment. This project was implemented at a site where an operator previously tried combustion to recover oil and failed. The Bartlett project planners were unaware of this previous activity. A review of past state oil and gas records, as well as the trade journals' project activity data would have shown that the project was unlikely to succeed at the selected site. Several in situ combustion projects were successfully carried out in Bartlesville sand reservoirs and case histories published. Examination of these case histories would have revealed that the successful exploitation of oil reservoirs in the Bartlesville sand by in situ combustion requires special engineering considerations due to their anisotropic characteristics and how this can be accomplished. Lack of a thorough study of published information was one of the causes of failure of the Bartlett combustion project.

It should also be kept in mind that each reservoir is unique, and each presents a new challenge to the development of a design that will accommodate the unique reservoir characters. Project design based on combustion parameters determined using core and oil samples from the project site are less likely to fail than those based on empirical correlations. Both the Appalachian area combustion projects, as well as the Bartlett combustion project, were designed using empirical correlations. As a result, the compressors were undersized and failed frequently due to overloading. Frequent compressor downtime was yet another reason why these projects failed.

Combustion projects are less likely to succeed in shallow reservoirs containing very volatile or very viscous oil and must be avoided. The Appalachian area in situ combustion projects were carried out in very shallow reservoirs containing a highly volatile oil. The distillation characteristics of these oils are such that more than 60% of the oil vaporizes below 500° F, thus leaving very little fuel for combustion. In situ combustion projects were successfully implemented in very light oil reservoirs, such as the May-Libby field in Louisiana, but these occurred in deeper formations with the oil less volatile than the Appalachian area crude. The Paris Valley and the Little Tom field reservoirs contain highly viscous crudes and the inability to establish oil mobility after ignition was one contributing factor to their failure.

If possible, avoid implementing combustion projects in old properties. Most old properties contain wells that are improperly plugged and abandoned. Since the location of these wells are generally unknown, they become the conduit through which large amounts of air escape. The Bartlett and Appalachian area combustion projects were implemented in properties that were littered with unplugged wells of unknown locations. Many of these improperly abandoned holes revealed themselves when air escaped through them. Implementation of combustion projects in old properties requires special engineering consideration and modified operating practices.

The Bodcau in situ combustion project was successful because it avoided many of these shortcomings. The project was well planned and well designed. Considerable effort was devoted to the operation of the project. The operator left very little to chance and put his previous experience in operating combustion projects in an adjacent lease to full use. Instead of designing the project utilizing the reservoir properties of the adjacent lease, the operator drilled, logged, and cored five exploratory wells to confirm the geology and reservoir properties of the selected site and designed the project accordingly. Extensive combustion tube runs on site core material and oil provided the vital information needed to size the compressor. The operator also learned from the experience of Getty Oil Company's in situ combustion project in a neighboring lease and avoided some of the operational problems. As a result of a well-planned operation, the project recovered oil in excess of the projected value and provided lessons to others in how to plan, design, and operate a combustion project.

Last but not the least, the importance of a well-financed operation on the outcome of an in situ combustion project should not be overlooked. In situ combustion is a high cost operation and the success depends upon overcoming many costly operational hurdles. An underfinanced operation is one way to assure failure. The operation of the Little Tom combustion project, as well as the USBM's Appalachian area combustion projects and the DOE's Bartlett, KS, combustion project were severely affected by budget constraints. These projects were mired down with operational problems and could not be rescued due to paucity of funds. Underfinancing was cited as one of the major causes of failure for many early combustion projects.[24]

CONCLUSIONS

1. Of the eight cost-shared projects reviewed, only one (Bodcau In Situ Combustion Project) was deemed successful, both technically and economically.
2. Careful study of Bodcau Project indicated the recipe for success includes careful site selection, planning, design, engineering, and operation of the project. The analysis showed that very little was left to chance, and virtually all difficulties were foreseen and strong efforts made to deal with them. Operator's previous experience in the operation of combustion projects in an adjacent lease played a key role in the success of the project.
3. Review of failed projects indicate that the projects failed because the operators did not do their homework (lack of thorough study of past records of project site and case histories of projects implemented in similar reservoir settings, inadequate or no combustion tube runs, basing project design on empirical correlations rather than on combustion tube results, lack of understanding of process mechanisms, etc.) and threw caution to the wind.
4. Several combustion projects were successful in reservoirs similar to the failed projects. Analysis of the case histories of the successful projects indicated that the engineering design must take geology into consideration and the projects operational problems can be overcome by proper design procedures.
5. Significant advances have been made in the application of ISC technology to fields during the last 15 years. These advances, along with prudent engineering design and improved operating procedures, can enhance the success of many failed projects.

ACKNOWLEDGMENT

This work was supported by the U. S. Department of Energy under Contract No. DE-AC22-94PC91008 with BDM-Oklahoma, Inc. We wish to thank Thomas B. Reid of the U.S. DOE Bartlesville Project Office for encouragement to write this paper, Mr. Bruce Ramzel of BDM-Oklahoma for his help in gathering the materials and preparing the figures and Annalea Kerr of BDM-Oklahoma for her assistance in typing this paper.

REFERENCES

1. Holbrook, G. W., T. E. Hungerford and M. R. Rankine: A Fireflooding Experiment in the Bradford-Allegheny Area. *Producers Monthly*, Vol. 23, No. 10, October 1959, pp. 26–28.
2. Caspero, N. A., W. T. Wertman and W. E. Eckard. Underground Combustion Oil-Recovery Experiment in the Venango First Sand, Warren County, PA. U.S. Bureau of Mines Report of Investigation, RI6320, 1963, 39 pp.
3. Campbell, G. G., E. L. Burwell, T. E. Sterner and L. L. Core. Underground Combustion Oil Recovery Experiments in the Venango Second Sand, Reno Pool, Venango County, PA. U.S. Bureau of Mines Report of Investigation, RI6942, April 1967, 45 pp.
4. Campbell, G. G., E. L. Burwell, T. E. Sterner and L. L. Core. Why a Fireflood Project Failed. *World Oil*, Vol. 162, No. 2, February 1, 1966, pp. 46–50.
5. Ireton, E. T. Little Tom Thermal Recovery Demonstration Project, Zavala County, Texas—Final Report. U.S. Dept. of Energy Report No. BERC/RI-76/13, January 1977, 31 pp.
6. Shipley, R. G. Jr., R. F. Meldau, P. D. White and J. W. Patek. Paris Valley Combination Thermal Drive Pilot Demonstration Test—Final Report. U.S. Dept. of Energy Report No. DOE/SAN/1000-3, September 1980, 203 pp.
7. Hardin, G. Bodcau In Situ Combustion Project—4th Annual Report. U.S. Dept. of Energy Report No. DOE/ET/12057-8, July 1981, 98 pp..
8. Little, T. P. Bodcau In Situ Combustion Project—Precontract work and Plan for Project Development. U.S. Dept. of Energy Report No. SAN-1189-77-1, March 1977, 97 pp.
9. Stair, J. R. Lynch Canyon Combination Thermal Drive Project—Final Report, U.S. Dept. of Energy Report No. DOE/ET/12086-1, November 1980, 91 pp.
10. Miller, J. S. and L. K. Spence. In Situ Combustion Project at Bartlett, Kansas—Final Report, U.S. Dept. of Energy Report No. DOE/BETC/RI-83/3, April 1983, 51 pp.
11. Moore, R. G. New Strategies for In Situ Combustion. *J. Canada Pet. Tech.*, Vol. 32, No. 10, December 1993, pp. 11–13.
12. Moore, R. G., J. D. M. Belgrave, R. Mehta, M. Ursenbach, C. J. Laureshan and K. Xi. Some Insight into the Low-Temperature and High-Temperature In Situ Combustion Kinetics, Paper SPE/DOE 24174 presented at the 8th Symposium on Enhanced Oil Recovery, Tulsa, OK, April 22–24, 1992.
13. Joseph, C. and J. G. Hardin. Bodcau In Situ Combustion Project, Bellevue Field, Louisiana. Paper presented at the 1981 Annual Heavy Oil/EOR Contractor Meeting. U.S. Dept. of Energy Report No. CONF-81078, July 1981, pp. G1–G10.
14. Joseph, C., C. B. Jay, E. V. Eslinger and C. J. Mundis. Evaluation of an In Situ Combustion Process by Postburn Core and Log Analysis. Paper SPE 10766 presented at the SPE California Regional Meeting, San Francisco, CA, March 24–26, 1982.
15. Goebel, E. D. Thermal Recovery Projects are Increasing in Kansas, Missouri. *World Oil*, Vol. 162, No. 4, March 1966, pp. 78•80.
16. Hardy, W. C. In Situ Combustion in a Bartlesville Sand—Allen County, Kansas. Paper presented at the University of Kansas 1st Annual Tertiary Oil Recovery Conference, Wichita, KS, October 23–24,

1975. Proceedings (Contribution #2) Published by Tertiary Oil Recovery Project (TORP), Institute of Mineral Resources Research, University of Kansas, Lawrence, KS, 1975.

17. Hardy, W. C., P. G. Fletcher, J. C. Shepard, E. W. Dittman and D. W. Zadow. In Situ Combustion in a Thin Reservoir Containing High-Gravity Oil. J. Pet. Tech., Vol. 24, No. 2, February 1972, pp. 199–208.
18. Buchwald, R. W. Jr., W. C. Hardy and G. S. Neinast. Case Histories of Three In Situ Combustion Projects, *J. Pet. Tech.*, Vol. 25, No. 7, July 1973, pp. 784–792.
19. Emery, L. W. Results From a Multi-Well Thermal-Recovery Test in Southeastern Kansas, *J. Pet. Tech.*, Vol. 14, No. 6, June 1962, pp. 671–678.
20. Barnes, A. L. Results From a Thermal Recovery Test in a Watered Out Reservoir, *J. Pet. Tech.*, Vol. 17, No. 11, November 1965, pp. 1343–1353.
21. Elkins, L. F., A. M. Skov, P. J. Martin and D. R. Lutton. Experimental Fireflood—Carlyle Field, Kansas. Paper SPE 5014, presented at the Soc. of Pet. Engineer's 49th Annual Fall Meeting, Houston, TX, October 6–9, 1974.
22. Casey, T. J. A Field Test of the In Situ Combustion Process in a Near-Depleted Water Drive Reservoir. *J. Pet. Tech.*, Vol. 23, No. 2, February 1971, pp. 153–160.
23. Burger, J., P. Sourieau and M. Combarnous. Thermal Methods of Oil Recovery, Chapter 6, Section 6.42, *Gulf Publishing Company, Book Division*, Houston, TX, 1985.
24. Mahony, B. J. Thermal Recovery Projects Spark Kansas Lease Play. *World Oil*, Vol. 159, No. 4, September 1964, pp. 110–114.
25. Smith, M. W. Simultaneous Underground Combustion and Water Injection in the Carlyle Pool, Iola Field, Kansas. *J. Pet. Tech.*, Vol. 18, No. 1, January 1966, pp. 11–18.

TABLE 1
RESERVOIR AND FLUID CHARACTERISTICS OF BRADFORD SAND KNIGHT FARM LEASE, ALLEGHENY FIELD[1]

Depth, ft	1,120
Project size, acres	4
Avg. pay thickness, ft	49
Porosity, %	15.8
Permeability, mD	23.8
Oil Satn. at the start of fireflood, % PV	35
Oil Satn. at the start of fireflood, bbl/ac-ft	420
Oil gravity, °API	44
Oil viscosity, cP at BHT	4
Reservoir temperature, BHT, °F	60

TABLE 2
SUMMARY OF BRADFORD COMBUSTION PROJECT RESULTS[1]

Number of ignition attempts	4
Date first ignition attempt	6/26/58
Date final ignition attempt made	8/29/58
Duration of ignition, days	106
Total air injected, MM SCF	12.206
Average daily air injection rate, MSCFD	115
Average injection pressure, psi (wellhead)	800
Produced gas analysis:	
Carbon dioxide, %	0.4
Oxygen, %	18.98
Nitrogen, %	79.30
Other, %	1.32
Gas production rate, MScf/D	84.5

TABLE 3
RESERVOIR AND FLUID CHARACTERISTICS OF VENANGO FIRST SAND HUNTER LEASE, GOODWILL HILL–GRAND VALLEY FIELD WARREN COUNTY, PA[2]

Depth, ft	400
Project size, acres	0.85
Avg. pay thickness, ft	25
Porosity, %	14
Permeability, mD	70
Oil Satn. at the start of fireflood, % PV	26
Oil Satn. at the start of fireflood, bbl/ac-ft	243
Oil gravity, °API	44
Oil viscosity, cP at BHT	4
Reservoir temperature, BHT, °F	60

TABLE 4
RESERVOIR AND FLUID CHARACTERISTICS OF VENANGO SECOND SAND, RENO POOL FOSTER-RENO-OIL CITY FIELD VENANGO COUNTY, PA[3]

Depth, ft	600
Project size, acres	1.61
Avg. pay thickness, ft	27
Porosity, %	13
Permeability, mD	57.8
Oil Satn. at the start of fireflood, % PV	37
Oil Satn. at the start of fireflood, bbl/ac-ft	460
Oil gravity, °API	40
Oil viscosity, cP at BHT	39
Reservoir temperature, BHT, °F	61

TABLE 5
RESERVOIR AND FLUID CHARACTERISTICS, SAN MIGUEL SAND, LITTLE TOM FIELD, ZAVALA COUNTY, TEXAS[5]

Depth, ft	2,800
Average pay thickness, ft	40
Average porosity, %	22.3
Average permeability, mD	64
Average water saturation, % PV	40
Average oil saturation, % PV	60
Average Saturation at the start of fireflood, bbl/ac-ft	988
Reservoir pressure, psig	750
Reservoir temperature, °F	125
Oil gravity, °API	14.3
Oil viscosity (dead), cP, 70°F	230

TABLE 6
AVERAGE RESERVOIR AND COMBUSTION CHARACTERISTICS OF ANSBERRY SAND PARIS VALLEY FIELD[6]

Reservoir depth, ft	800
Porosity, % PV	32.2
Permeability, mD	3,748
Oil saturation, % PV	63.7
Water saturation, % PV	36.3
Oil in place, bbl/ac-ft	1,801
Oil in the pilot area, MM STB	2.6
Average net pay thickness, ft	58
Reservoir pressure, psia	235
Reservoir temperature, °F	87
Oil gravity, ° API	10.5
Oil viscosity, cP at reservoir temperatures	
Upper Lobe	227,000
Lower Lobe	23,000
Formation volume factor, STB/RB	1.0
Fuel requirement: Lbs/ft^3	2.33
Bbl/ac-ft	295
Air required for combustion: Scf/ft^3	417
MScf/ac-ft	18,165
Oil displaced from burned zone, bbl/ac-ft	1,296

TABLE 7
RESERVOIR AND FLUID CHARACTERISTICS OF NACATOCH SAND, BODCAU LEASE, BELLEVUE FIELD, BOSSIER PARISH, LA[8]

Depth, ft	450
Project size, acres	19
Avg. pay thickness, ft	54
Average porosity, %	33.9
Average permeability, mD	700
Water saturation, % PV	27.4
Oil saturation, % PV	72.6
Oil Satn. at the start of fireflood, STB/ac-ft	1,909
Reservoir pressure, psig	40
Reservoir temperature, °F	75
Oil gravity, °API	19
Oil viscosity at reservoir temperature, cP	676
Dip angle, degrees	4.5

TABLE 8
ESTIMATED RESERVOIR AND FLUID PROPERTIES OF LANIGAN SAND, LYNCH CANYON FIELD, PRIOR TO INITIATION OF THERMAL PROJECT[9]

Depth, ft	1,800
Size, acres	400
Average thickness, ft of project site	40
Reservoir volume, ac-ft	12,500
Porosity, %	36.0
Permeability, mD	6,000
Fluid saturation, % PV	
Oil	74
Water	26
Gas	0
Oil gravity, °API	11
Estimated formation volume, factor	1.05
Original-oil-in-place, STB	26,000,000
Estimated oil content, STB/ac-ft	2,080
Reservoir pressure, psig	650
Reservoir temperature, °F	104
Estimated oil viscosity at 115° F, dead oil, cP	9,000

TABLE 9
ESTIMATED RESERVOIR AND FLUID PROPERTIES OF LANIGAN SAND, LYNCH CANYON FIELD, PRIOR TO AND AFTER COMPLETION OF PHASE I OPERATION[9]

PROPERTIES	PRIOR TO PHASE I	AFTER PHASE I
Average net pay thickness, ft	40	38
Porosity, %	36.0	34.0
Permeability, mD	6,000	6,000
Reservoir volume, ac-ft	12,500	8,130
Estimated oil-in-place, MM barrels	26	14.64
Estimated oil content, STB/ac-ft	2,080	1,800
Saturation, % PV		
Oil	74	69
Water	26	31
Gas	0	0
Reservoir temperature, °F	104	104
Oil Gravity, °API	11	10
Estimated oil viscosity @ 115° F, cP	9,000	70,000

TABLE 10
RESERVOIR AND FLUID CHARACTERISTICS OF BARTLESVILLE SAND, LINK LEASE, BARTLETT, KS[10]

Depth, ft	600
Project size, acres	1.25
Avg. pay thickness, ft	12
Average porosity, %	22
Average permeability, mD	177
Water saturation, % PV	35.3
Oil saturation at the start of fireflood, % PV	43.0
Oil Satn. at the start of fireflood, bbl/ac-ft	600
Reservoir pressure, psig	50
Reservoir temperature, °F	65
Oil gravity, °API	15
Oil viscosity at reservoir temperature, cP	1,270

TABLE 11
COMPARISON OF APPALACHIAN AREA FIREFLOOD PROJECTS RESERVOIR AND FLUID PROPERTIES WITH OTHER SUCCESSFUL HIGH GRAVITY FIREFLOOD PROJECTS

PROJECT INFORMATION	FIELD				
	BRADFORD[1]	VENANGO-1ST[2]	VENANGO-2ND[3]	MAY-LIBBY[17]	DELAWARE[20]
Location	Bolivar, NY	Warren County, PA	Reno, PA	Richland Parish, LA	Nowata County, OK
Year Proj. Initiated	1958	1961	1963	1966	1960
Operator	USBM	USBM	USBM	Sun	Sinclair
Project Size, ac	4	0.85	7.78	40	2.2
Project Status	Failed	Failed	Failed	Technical & Economic Success	Technical Success
Type of Secondary Recovery	Waterflood	Air Flood	None	Waterflood	Waterflooded to Depletion
Depth, ft	1,120	400	600	3,400	600
Thickness, ft	49	25	27	4.4	45.5
Lithology	Shaley Lime Sand	Shaley Lime Sand	Shaley Lime Sand	Relatively Clean Sand	Relatively Clean Sand
Porosity, %	15.8	14	13	31.2	20.6
Permeability, mD	23.8	70	57.8	1,069	118
Oil Satn. at the start of Fireflood, %	35	26	37	53	33
Oil Satn. at the start of Fireflood, bbl/ac-ft	420	243	460	1,395	460
Oil Gravity, °API	44	44	40	41	33
Oil Viscosity, cP @ BHT	4	4	3.9	3.0	6
BHT, °F	60	60	61	135	65
Air requirement, Scf/cu-ft	--	--	--	239	246
Fuel consumed, bbl/ac-ft	--	--	--	136	275
Fireflood Oil Recovery, bbl	--	--	--	163,084	12,980

TABLE 12
COMPARISON OF DISTILLATION CHARACTERISTICS OF A TYPICAL APPALACHIAN AREA RESERVOIR CRUDE WITH A LOUISIANA HIGH GRAVITY CRUDE
(All distillation are at atmospheric pressure)

% Distilled	Temperature, °F	
	Venango[3] 2nd sand, PA	May-Libby[17] LA
Initial	122	150
10%	255	255
20%	302	325
30%	396	412
40%	445	503
50%	502	570
60%	572	612
70%	--	635

TABLE 13
COMPARISON OF LITTLE TOM FIREFLOOD RESERVOIR AND FLUID PROPERTIES WITH OTHER SUCCESSFUL SOUTH TEXAS FIREFLOODS

PROJECT INFORMATION	FIELD			
	LITTLE TOM[5]	GLEN HUMMEL[18]	GLORIANA[18]	N. GOVT. WELLS[22]
Project Status	Technical Failure	Technical and Economic Success	Technical and Economic Success	Technical and Economic Success
Operator	Hanover Petroleum	Sun Oil	Sun Oil	Mobil Oil
Location	Zavala County	Wilson County	Wilson County	Duval County
Year Proj. Initiated	1975	1969	1969	1962
Proj. Size, ac	--	544	534	400
Depth, ft	2,800	2,432	1,600	2,320
Thickness, ft	30'	8' 8"	4' 4"	30'
Porosity, %	22.3	36	35	32
Permeability, mD	64	1,000	1,000	800
Oil Satn. at the start of Fireflood	0.6	0.7	0.68	0.58
Oil Satn. at the start of Fireflood, bbl/ac-ft	713	1,766	2,131	900
Oil Gravity, °API	18	21.9	20.8	22
Oil Viscosity, cP @BHT	90	74	174	10
BHT, °F	125	113	113	120
Air Requirement, Scf/ft^3	396	253	256	175
Fuel consumed, bbl/ac-ft	260	137	153	212
Fireflood Oil Recovery, bbl	--	1,204,000	1,540,000	676,000

TABLE 14
COMPARISON OF FAILED CALIFORNIA EXTRA HEAVY OIL IN SITU COMBUSTION PROJECTS

PROJECT INFORMATION	PARIS VALLEY[6]	LYNCH CANYON[9]
Project Status	Economic Failure	Project Aborted Prior to Ignition
Year Project Initiated	1975	1978
Operator	Husky Oil	Mobil
Project Size, ac	25	60
Depth, ft	850	1,800
Thickness, ft	48	38
Porosity, %	32.2	34
Permeability, mD	3,748	6,000
Oil Saturation, %	41.3	69
Oil Saturation, bbl/ac-ft	900	1,800
Oil Gravity, °API	11	10
Oil Viscosity, cP @ BHT	227,000 (Upper Lobe) 23,000 (Lower Lobe)	70,000
BHT, °F	87	104
Air Requirement, Scf/ft^3	417	364
Fuel Consumed, bbl/ac-ft	295	303
Fireflood Oil Recovery, bbl	2,731	--

TABLE 15
IN SITU COMBUSTION PROJECTS UNDERTAKEN IN BARTLESVILLE SANDSTONE[15]

NO.	YEAR	COUNTY AND STATE	OPERATOR	PROJECT NAME	FIELD	DEPTH, FT	THICKNESS, FT	OIL GRAVITY, °API	OIL VISC., CP	PROJECT STATUS
1	1956	Allen, KS	Sinclair	–	Humboldt	820	26	23	700	Technical and Economic Success
2	1957	Allen, KS	Great Western	–	Humboldt Chanute	810	22	23	670	Failed
3	1959	Crawford, KS	General Oil &Gas	McCune	McCune	400	24	21	900	Failed
4	1960	Nowata, OK	Sinclair	Delaware Childer	Delaware Childer	600	45	33	6	Technical Success
5	1961	Bourbon, KS	Standard Crystals Co.	Coonrod	–	400	21	21	700	Failed
6	1961	Labette, KS	Collins	Bartlett	Link Lease	360	14	15	1,270	Failed
7	1961	Neosho, KS	International	Erie	Erie	515	18	32	17	Failed
8	1962	Montgomery, KS	Sage	–	Coffeyville	1,200	30	24	280	Failed
9	1963	Franklin, KS	Cra Inc.	Broers	Baldwin	760	27	24	700	Failed
10	1963	Wilson, KS	Johnson & Wood	Roper	Buffalo-Vilas	1,000	22	21	300	Failed
11	1963	Allen, KS	Layton Oil	Carlyle	Iola	860	35	20	700	Technical Success
12	1965	Allen, KS	Sun Oil	Stewart	Moran	830	17	21.2	750	Technical Success

TABLE 16
COMPARISON OF BARTLETT (U.S. DOE) COMBUSTION PROJECT RESERVOIR AND FLUID PROPERTIES WITH OTHER SUCCESSFUL BARTLESVILLE SAND FIREFLOOD

PROJECT INFORMATION	FIELD BARTLETT[10]	HUMBOLDT CHANUTE[19]	CARLYLE IOLA FIELD[21,25]	SUN IOLA PROJECT[16]
Operator	U.S. DOE	Sinclair Oil Co.	Layton Oil Co.	Sun Oil Co.
Location	Labette County, KS (Link Lease)	Allen County, KS (Baker Lease)	Allen County, KS (Wiggins Lease)	Allen County, KS (Moran Field)
Year Project initiated	1980	1956	1963	1965
Project Size	1.25 acres	60 acres	11 acres	20 acres
Project Status	Technical Failure	Technical & Economic Success	Technical Success	Technical Success
Depth, ft	360	820	860	830
Thickness, ft	12	26	35	17
Porosity, %	22	20.3	25.3	21.2
Permeability, mD	177	85	200	88.1
Oil Saturation at the start of Fireflood, %	43	61	57	70
Oil Saturation at the start of Fireflood, bbl/ac-ft	790	1,089	1,000	1,159
Oil Gravity, °API	15	23	20	20.1
Oil Viscosity, cP @ BHT	1,270	670	700	750
BHT, °F	72	78	78	77
Lithology	Shaley Sand	Shaley Sand	Shaley Sand	Shaley Sand
Air Requirement, Scf/ft^3	397	182	--	310
Fuel Consumed, bbl/ac-ft	212	146	--	210
Fireflood Oil Recovery, bbl	910	79,000	32,500	51,212

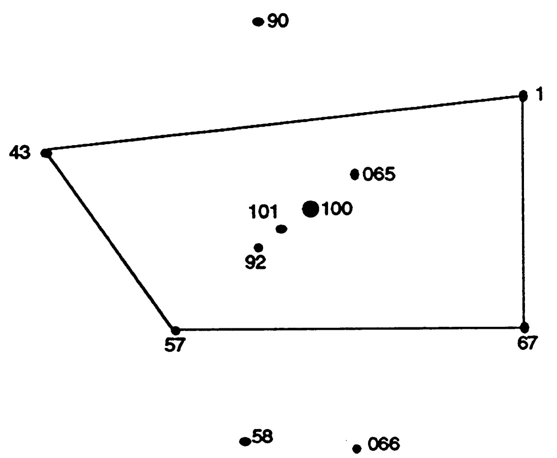


Fig. 1 Bradford Sand combustion test—well pattern.

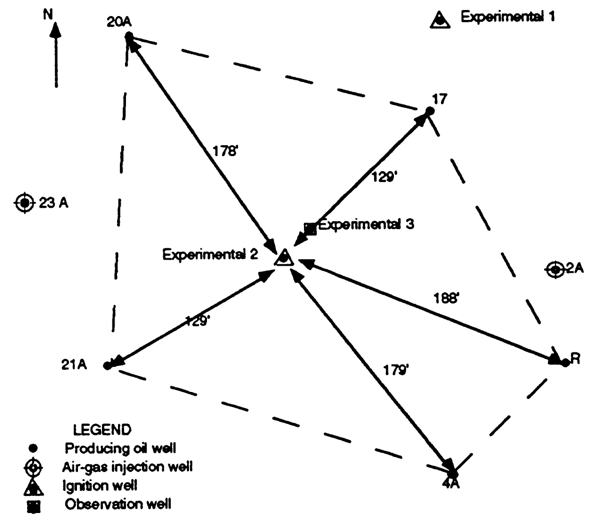


Fig. 2 Venango First Sand in situ combustion test well pattern.

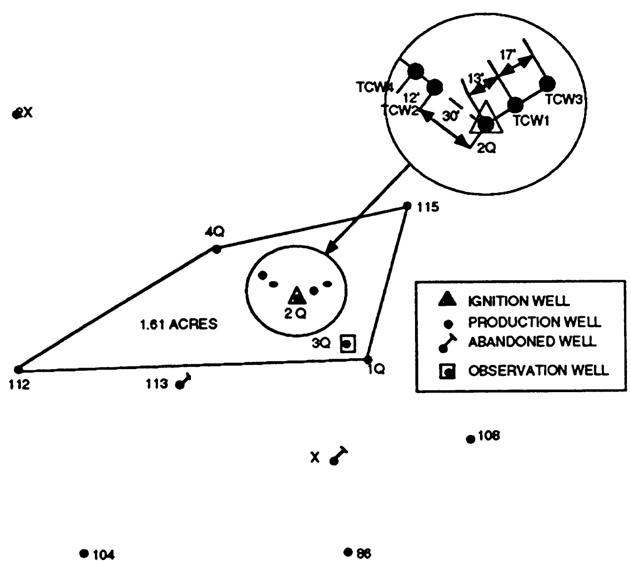


Fig. 3 Venango Second Sand in situ combustion experiment—well pattern.

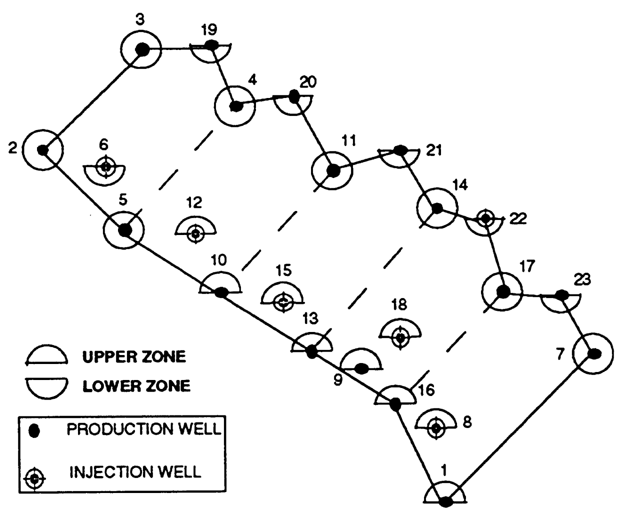


Fig. 4 Paris Valley in situ combustion project well pattern map.

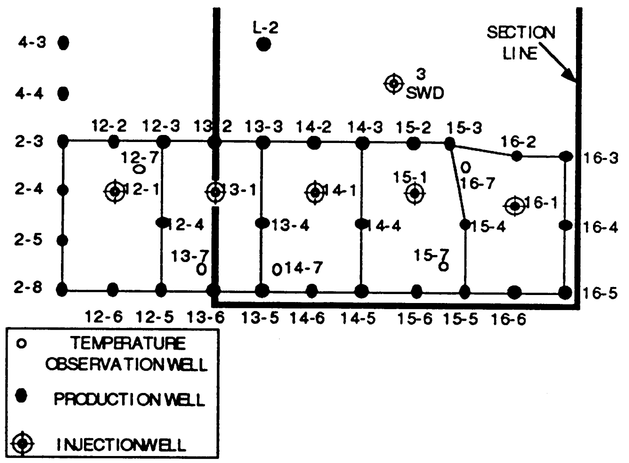


Fig. 5 Project pattern map of Bodcau fireflood project.

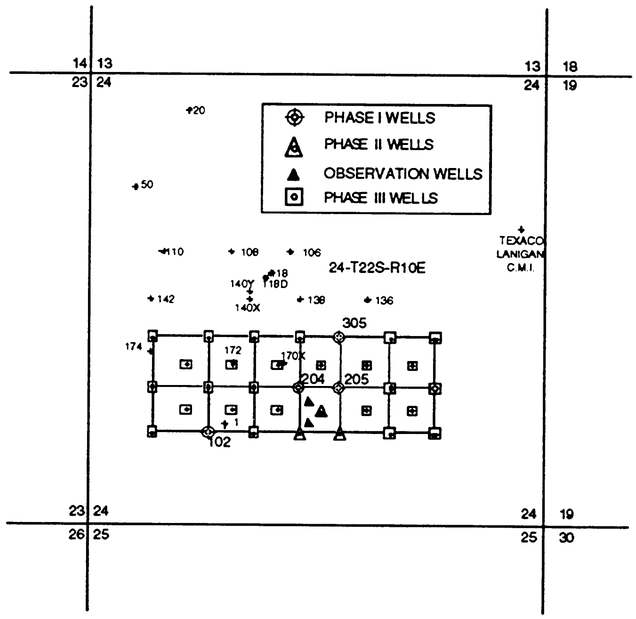


Fig. 6 Lynch Canyon fireflood project well pattern map.

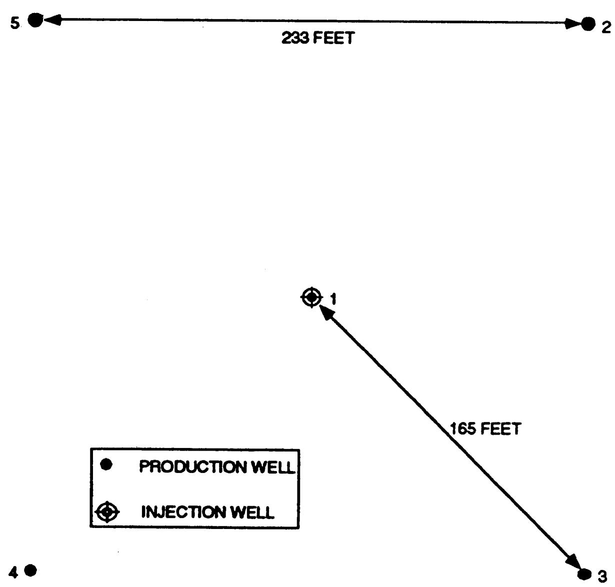


Fig. 7 Bartlett site well patterns.

No. ISC 5

DOE/NIPER

In Situ Combustion Field Experiences in Venezuela

by M. Villalba, M. Estrada and J. Bolivar, INTEVEP, S.A., Caracas, Venezuela

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

A literature review of four in situ combustion projects: in Miga, Tía Juana, Melones and Morichal fields in Venezuela was made, and a summary of these projects is presented. Reservoir description and project performance data were analyzed.

The behavior of the four in situ combustion field tests can be summarized as follows:

- The problems most often encountered were corrosion and high temperature producing wells.
- The direction in which the burning front moved was guided essentially by reservoir characteristics.
- The produced oil was upgraded by about 4° API, and viscosity was substantially reduced.
- For Morichal and Miga fields, the analyses of available information from the combustion projects indicated that the process had been successful in the affected region.

Conclusions from this review indicate that the two most frequent problems encountered were operational problems in producing wells and the direction of the burning front. The heterogeneous nature of the sands probably resulted in the burning front moving in a preferential direction, hence reducing areal sweep efficiency.

References, tables and illustrations at end of paper.

INTRODUCTION

In situ combustion has been used for production of heavy oil reservoirs for the last fifty years. However, the number of projects which use this technique has decreased in the last two decades.

In Venezuela, the first in situ combustion projects started at the beginning of the 1960s. Their impact was overshadowed, at that time, by operational problems (oil emulsification, corrosion of well equipment, etc.) and the accidental discovery of the cyclic steam injection process. Cyclic steam has since become the most successful and economic technique used in Venezuelan heavy oil fields. In spite of all the disadvantages of the in situ combustion technique, it still has a high potential for application to tar sand and heavy oil reservoirs. Among its advantages are high thermal efficiency, low impact on the environment, and it uses less fuel than cyclic steam injection.

Todays advances in material sciences, corrosion control and new methodology in the characterization and description of oil reservoirs have led us to re-evaluate old in situ combustion projects. The purpose of this work is to show the main results of the evaluations and analyses of four Venezuelan in situ combustion projects.

SUMMARY OF PROJECTS

Morichal Field Test

This reservoir is located in Monagas State in eastern Venezuela, approximately 150 km south of the city of Maturín (see Fig. 1).

An in situ combustion pilot test[1,2] was conducted in 1960 in an unconsolidated reservoir to investigate the possibility of recovering heavy (9° to 12° API) oil at a depth of 3,500-4,000 ft. Primary recovery from these very flat reservoirs is low (2 to 7%), and oil viscosities range from 400 to 1,850 cP at reservoir temperature.

An isolated two-spot pattern with 329-ft spacing was selected for this test. This was a modest initial venture designed to yield maximum information in the shortest possible time.

Reservoir Description

This reservoir is of the Oligocene-Miocene Age. The sand selected for this project is unconsolidated, with a porosity of 33-35% and permeabilities ranging from 2 to 5 darcies, and an average sand thickness of 23 ft. Initial oil saturation was estimated to be 94%. Table 2 shows some of the reservoir characteristics. The crude oil is characterized by low gravity (9-12° API) and a high viscosity 1,700 cP at reservoir temperature of 145° F. The initial reservoir pressure was 1,600 psi, but it had dropped to about 1,360 psi by the time air injection commenced.

Completions

The injection well was initially a conventional heavy oil production well completed with 7-in. casing, 3 1/2 in. OD slotted liner, and a gravel pack. Conversion to an injector required the production casing to be replaced with 3 1/2 in. OD chrome alloy injection casing.

The producing wells were equipped with 9 5/8 in. OD slotted liners.

Performance Data

Air injection began on June 8, 1960, and the pressure stabilized at 1,425 psi. Two days after pressure stabilization, there was evidence that spontaneous ignition had occurred, and pressure restabilized at 1,700 psi. Ignition was confirmed on August 18 by analyses of produced gas at offset wells which showed 9.8% CO_2. Oxygen was never detected.

Net oil withdrawals from the producing well are shown at the bottom of Fig. 2. After the well was placed on sustained production, offtake averaged 140 BOPD until the effect of the combustion front was felt in 1962. Fig. 2 shows that the bottom-hole temperature was initially 145° F and that the gravity of the produced oil averaged a constant 9.5° API. The first effect of the combustion was manifested in an increasing API gravity of the oil. Oil gravity changed from 9.5 in August 1961 to 12.2° API in January 1962 and then declined. This was oil cracked by the combustion and subsequently cooled as it moved downstream. Almost simultaneously the water cut increased sharply indicating arrival of the waterbank. In November 1961, the temperature began to rise reaching 350° F. In February 1962, the offtake rate rose to 285 BOPD.

Because movement of the combustion front to the production wellbore itself was not desired, air injection was terminated on May 17, 1962. Within a month, the producing well was closed in to await a pumping installation. Air-oil ratio at completion of air injection was 7.68 MSCF/STB.

Injection production history after air injection termination can be followed in Figs. 3 and 4. The oil production rate rose gradually, peaking at 365 BOPD in July 1963, and thereafter declining to 100 BOPD in June 1964 when the test was terminated. The declining production rate was almost directly related to the declining BHT (top of Fig. 2).

Finally, more than 60% of the project's production was obtained subsequent to air injection termination. An estimated 10,424 bbl of fuel was consumed by the combustion. A computed upper limit to the specific fuel consumption was 2.20 lb fuel-cu ft rock.

The main conclusions of the test were the following:

1. Spontaneous ignition was obtained.

2. Injected oxygen was completely utilized.

3. Thermal cracking caused an upgrading of up to 4° API of some of the crude oil displaced during combustion.

4. A bottomhole temperature increase from 145° to 250° F increasing the production rate sixfold over that anticipated from the decline curve of other wells in the field.

Miga Field Test

The Miga field is located approximately 25 km south of San Tomé, Anzoategui State in the northeastern part of Venezuela (See Fig. 1).

From 1964 to 1985 a fireflood project[3,4] was carried out in the P2-3 sand reservoir in the Miga field to stimulate production of 13° to 14° API heavy oil.

The original-oil-in-place was estimated at 22 million barrels. Only 1.2 million, or 5%, was expected to be produced by primary depletion. Up to April 1983, about 5 million barrels of oil or 25% of the original-oil-in-place were recovered by the use of the in situ combustion process, and about 50 billion SCF of air had been injected. The air injection rate averaged about 10 MMCF/D over the life of this project. The air-oil ratio averaged 12 MSCF/STB. Based on this air-oil ratio, the project was considered to be a technical and economic success.

Reservoir Description

The P2-3 channel sands of the Miga field are part of the Oficina formation. They are Oligocene-Miocene Age and consists of numerous channel type sands which are lenticular and vary in thickness.

The depth of the reservoir ranges from 4,000 to 4,350 ft with dip of about 2 degrees. The sand is loosely consolidated, with a porosity of 22.6% and an estimated average permeability of 5 darcies. Maximum sand thickness is about 25 ft. Connate water saturation is about 22%. Oil gravity ranges from 13° to 14° API with a corresponding viscosity span of 280 cP to 430 cP at the prevailing reservoir temperature of 146° F. Estimated oil saturation at the start of the project was 75%.

Reservoir pressure was 1,800 psi during early primary production. It was estimated at 1,520 psi at the start of the in situ combustion project. The pressure peaked at 2,310 psi during the early stage of the fireflood project.

Interpretation of the reservoir configuration changed considerably as the drilling of new wells progressed. The changes are shown in Fig. 5.

This reservoir was selected for the project because of its size and configuration (i.e.—the confined nature of the reservoir which kept communications with other sands to a minimum, the elongated shape, the relatively low thickness, and the slight dip of the reservoir). Air injection points were selected to take advantage of these features.

Completions

The injection well was completed with 4 1/2-in., chrome hydril casing and a permanent packer. To protect the upper casing against oxygen corrosion, the annulus was filled with fresh water containing sodium sulfite, an oxygen scavenger. The offtake wells were completed with 7-in., 20 lb, J-55 casing. All wells were completed with 3-in. slotted liners with inside gravel packs and put on pump.

Performance Data

Air injection began on April 1, 1964, with five producers in operation. It was ascertained from the gas sampling results that spontaneous ignition had occurred by mid-May 1964. The production performance of the project is shown in Figs. 6 to 7.

Injection of air into well MG-525 continued until September 1969, when injection was moved to well MG-825. From April 1964 to September 1969, the average injection rate was about 11.2 MMSCF/D. Poor injectivity in well MG-825 was experienced due to the shaley nature of the 15-ft sand. As the project continued, the air injection rate was decreased to divert a portion of the air to another fireflood in a neighboring reservoir. The air rate was reduced to 4 MMSCF/D by 1976 and to as low as about 2.7 MMSCF/D in 1981. Beginning in March 1978, injection of a portion of the air into well MG-548 (a new injector) had begun.

The in situ combustion project in the Miga P2-3 reservoir had many upsets, including drastic changes in the injection and production schedule. During the first years of the project, the air injection rate was very high. During those years, sufficient air reached the combustion front, and the high temperature combustion front moved rapidly toward the producing wells. After these early years, the air rate gradually came down from a high of 14 MMSCFD to a low rate of less than 3 MMSCFD. It appears that as the front moved further and further away from the injection wells, less and less air could be injected.

The accumulative air-oil ratio remained fairly stable between 11-12 MSCF/STB throughout the project. For such low gravity oil, this was an economically viable ratio.

The total oil production from the MG-517 reservoir was 4.81 millions barrels to October 1980. Of this, 0.779 million barrels were produced on primary between the time of reservoir discovery (1958) and the start of the combustion process in April 1964. The primary production rate was at least doubled, and possibly increased by as much as four-fold, by the combustion process. Additional in-fill wells would not have been economically justified for primary production relative to the production results of the combustion process.

The value derived for fuel consumption from field performance was 2.0 lb/cu ft of rock.

The injection/production behavior of the reservoir indicated that the combustion process had been confined to the reservoir and that there had been no major communication problems with other nearby sands.

The oil production rate peaked in 1967 and then slowly decreased until the latter part of 1976, when it reached a low production rate plateau of 150-300 B/D. The air injection rate had the same pattern, leveling off at 3 MMSCF/D. The reason for the gradually declining performance may be due to operational/economic factors such as the production of emulsions and H_2S from some producing wells, etc. The air compressor plant was initially designed to have a maximum delivery capacity of 15 MMSCF/D using 5 compressors. However, due to operational problems, the plant could not provide more than 10 MMSCF/D and later in the project could only supply 4 MMSCF/D.

The following conclusions have been drawn regarding the behavior of the project:

1. The final air injection rate (3 MMSCFD) was not sufficient for advancing a high temperature burning front throughout the reservoir.

2. The confined nature of the reservoir kept communications with other sands to a minimum and contributed to the favorable performance of the process.

Melones Field Test

A single injection well pilot test[5,6] was carried out in 2.06 acres of the Melones field from 1977 to 1978. The purpose of the test was to evaluate the combination of forward combustion and water injection in an Orinoco heavy oil reservoir. Figure 1 shows the location of the Melones field in the northeastern part of Venezuela.

The reservoir in the pilot area had a porosity of 30%, a permeability of 1-2 Darcies, and an average sand thickness of 40 ft. The reservoir contains an 11-12° API, 50 cP oil. The initial oil saturation of the sand was 82%.

The pattern consisted of an inverted five-spot with a well spacing of 212 ft and two observation wells. The injection well was completed with 7-in., N-80 casing using a 2 7/8-in OD production string.

Performance Data

This pilot test was carried out in two phases. In the first phase, air injection was started on May 31, 1977, and water injection began 24 hours later. The ratio of air to water injected was 3.0 MSCF/B. This ratio was obtained from laboratory in situ combustion tube experiments.[6]

This project encountered many difficulties in the oil production wells. Plugging of the wellbore by sand caused the productivity to decrease, and workovers were necessary in August 1977 (Fig. 8). During this period, the loss of large amounts of injected air through the casing to the overburden was observed, leading to the suspension of air injection. Once this problem was overcome, the test was reinitiated from January 14 until 31 of 1978. At this time, an increase in CO_2 concentration was observed, as well as a temperature rise in the injector well, confirming combustion by spontaneous ignition. However, failure in the compression units along with high temperature in the injection well caused severe operational problems leading to the suspension of the pilot test. By the end of the test, in January 30, 1978, 94,500 barrels of oil had been produced.

Tia Juana Field Test

From November 1959 until February 1962, an in situ combustion field test[7] was carried out in Block K-7 east of Tía Juana. The purpose of the test was to evaluate the feasibility of this thermal recovery method under prevailing conditions along the Bolivar Coast of Lake Maracaibo (Fig. 1). The test consisted of one inverted seven-spot pattern with one injection well (I-1) and six producers (P-1, P-2, P-3, P-4, P-5 and P-6) (Fig. 9) with 438 ft spacing between injector and producer. Additionally, three observation wells (0-1, 0-2 and 0-3 moving from south to north) were drilled north of I-1 during the first year after test initiation. In July 1961, a core hole (LSE-2648) was drilled 264 ft. south of (I-2), close to P-3, P-4 and P-7, to investigate whether air or combustion oil was going out of the project sand.

Test Performance

Air injection started on November 4, 1959. Spontaneous ignition was established five weeks later when the temperature in the injection well increased to 482° F and carbon dioxide concentration in the produced gas of the producing wells started to increase.

During the first year of the test, the air injection rate varied from 2,000 to 3,200 MSCF/D. This was later lowered to 1,700-1,800 MSCF/D to reduce the advance of the combustion front and to redirect it in a preferential direction. As a result, injection pressures ranged between 450 and 500 psi.

Only four wells clearly responded to combustion the first year of the test (O-1, O-2, P-7 and P-3) as can be seen in the Fig. 10. Progress of the combustion front in a northerly direction was marked by temperature response in the observation wells O-1 and O-2, where temperatures rose to 1,742° F and 752° F, respectively. No significant temperature change was observed in well O-3. During the first six months, lateral distribution of the injected air seemed to be regular. However, in mid 1960, a decrease in the gas production at wells P-1 and P-6 coincided with a rise of gas production from the second row wells LSE-1439, 1522 and 1632 located close to P-3.

Early reaction of pattern well P-3, together with the high gas production from the outlying wells behind P-3, indicated that combustion was advancing preferentially in a southeasterly direction.

In an attempt to redirect air flow back towards the main pattern, wells LSE-1439, 1522 and 1632 were closed, since total gas production of the three wells had reached 60% of the air injection rate. However, no change resulted in the air flow within the pattern, and an increase of gas production from the third row wells was observed. Most likely this gas was that which was previously flowing to the now closed second row wells.

Based on the gas production rates from the pattern wells and outlying wells, air distribution and combustion at four different stages can be seen in Fig. 11. The amount of air flowing through each sector, as arbitrarily defined, was proportional to the gas produced by wells located in that sector.

As indicated before, well P-3 (P-3A) responded early to the combustion process. In fact, it was the only well which produced a significant amount of extra oil. Its cumulative oil production when air injection stopped was 21,860 barrels, 55% attributed to combustion. Cumulative oil production for each one of the pattern wells is shown in Table 3. Average pattern oil production rate increased gradually up to 150-300 B/D gross (50-170 B/D net) and average gas production reached a maximum of 1,300 MSCF/D. Oil gravity increased, rising from 13.5° to 16° API. Based on air consumption of around 600 SM^3/M^3 of rock, 78300 M^3 of formation was burned, and 130,000 barrels of oil should have been displaced. It should also be mentioned that 16,260 barrels of the final cumulative oil production from well P-3 occurred after termination of air injection.

In general, as a result of the field test in Tía Juana, the following aspects should be mentioned:

1. Only one well of the pattern exhibited a major production response from the main air flow channel. Most of the air escaped outside of the test pattern as did the oil displaced by combustion.

2. Slow oxidation of the oil led to spontaneous ignition five weeks after air injection started.

3. Although a gas injection pre-test showed good gas permeability distribution, heterogeneities of the formation determined the final gas distribution and outcome of the combustion process.

4. Performance of well P-3A showed that it is possible to produce from a properly completed well for a considerable period of time after the arrival of the combustion front.

CONCLUSIONS

From the literature review of four in situ combustion field tests done in Venezuela, it can be concluded that the two most frequent problems encountered were:

- Operational problems due to the high temperatures and corrosion problems in producing wells. However, reasonable procedures can be taken to reduce problems and to maintain and ensure the viability of projects, including circulation of cooling water, well completions using either stainless steel or chrome steel, and replacement of old wells near the thermal front with new productions wells.

- Controlling the direction and rate of the burning front. Combustion front breakthrough was often observed early in wells which were located in the direction of preferential air flow. This problem emphasizes the need for a good description of reservoir characteristics which is critical in designing a successful in situ combustion project.

Another important aspect of these pilot tests was that the produced crude oil was upgraded on an average of about 3-4° API. High oil production was often observed even after the combustion test was finished.

REFERENCES

1. Bowman, C.: "A Two-Spot Combustion Recovery Project." *J.P.T.* (September 1965), pp. 994-998.
2. Gallardo, B.: "Historia de los procesos de recuperación mejorada en el sur de Monagas." Informe LAGOVEN, Julio 1989.
3. Bandyopadhyav, P., and F. Cordero: "Evaluation of The Miga In-Situ Combustion Project." Informe MENEVEN. Julio 1983.
4. Cordero, F., and J. Mosquera: "Análisis del comportamiento de los proyectos de combustion "In-Situ, Campo Miga." Informe CORPOVEN, Junio 1987.
5. Negron, E.: "Proyecto piloto de combustión, Complejo Melones." Informe CVPSA, Enero 1977.
6. Estrada, M.: "Proyecto piloto de combustión húmeda In-Situ", Campo Melones." Informe CORPOVEN, Agosto 1979.
7. Schipper, L.: "Underground Combustion Drive Test, Tía Juana." Informe Interno. September 1962.

ACKNOWLEDGMENTS

The authors wish to thank to PDVSA and INTEVEP, S.A. for permission to publish this paper.

TABLE 1

In-situ Combustion Field Tests in Venezuela

Project	Started year	Pattern type	Acres	Primary recovery (% OIP)	Air/oil (SCF/STB)	Type process
Tía Juana	1959	7 spot	11	14	--	Dry
Morichal	1960	2 spot	--	3	2,858	Dry
Miga	1964	irregular	1,240	5	11,000	Dry
Melones	1977	5 spot	2.06	--	11,391	Wet

TABLE 2

Summary of Reservoir Characteristics of In-Situ Combustion Projects in Venezuela

Project	Temperature (°F)	Depth (ft)	Permeability (D)	Porosity (%)	Sand Thickness (ft)	Oil Saturation (%)	Oil Gravity (API)	Oil Viscosity (cP)
Tía Juana	145	1,585	5	40	50	80	12-16	500
Morichal	145	4,000	2-5	33-35	23	94	9-12	400-1850
Miga	146	4,050	5	22	15-25	75	13-14	280-430
Melones	180	--	1-2	30	40	82	11-12	50

TABLE 3

Cumulative Oil Production for Each One of the Pattern Wells, Tía Juana Field

P-1	13,780 bbls
P-2	1,272 bbls
P-3	1,301 bbls
P-3A	21,863 bbls
P-4	2,968 bbls
P-5	1,564 bbls
P-6	8,223 bbls
P-7	1,533 bbls

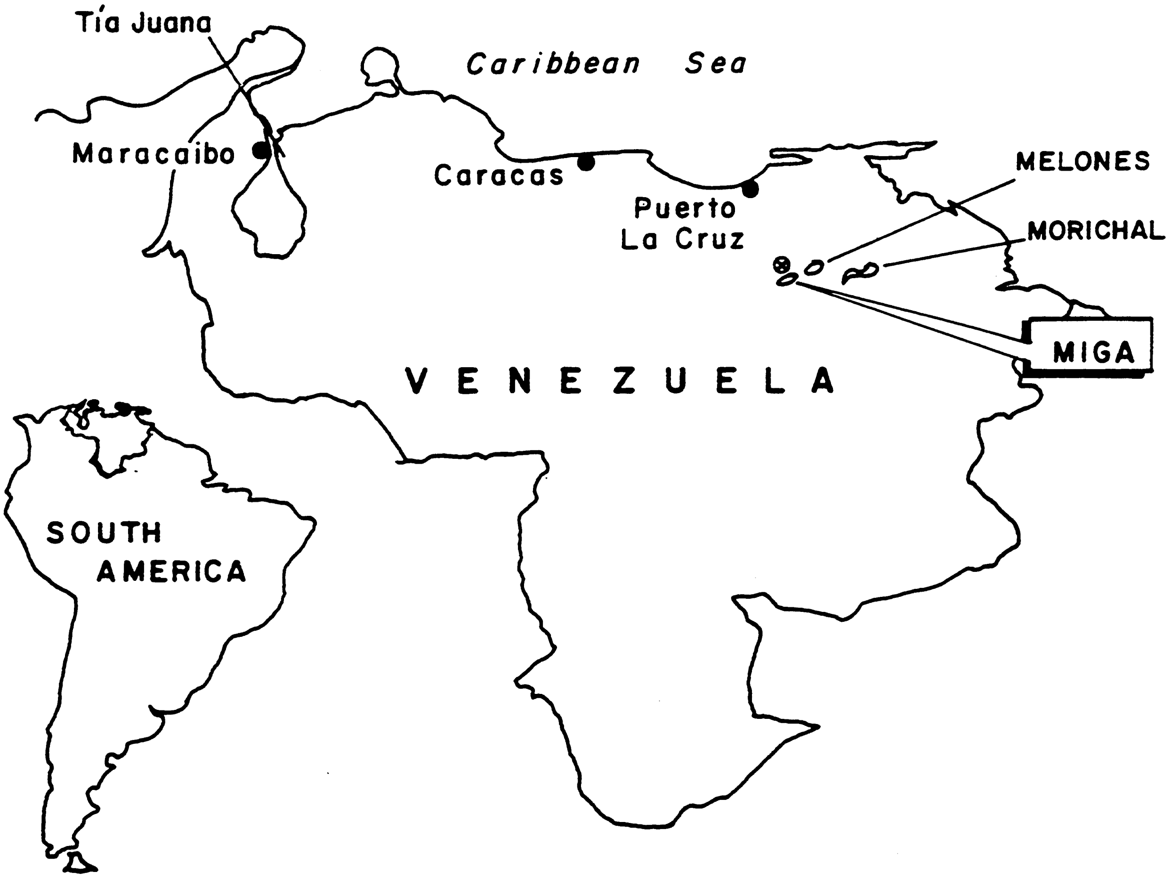


Fig. 1 GEOGRAPHICAL LOCATION OF THE MIGA, MORICHAL, MELONES, AND TIA JUANA FIELDS.

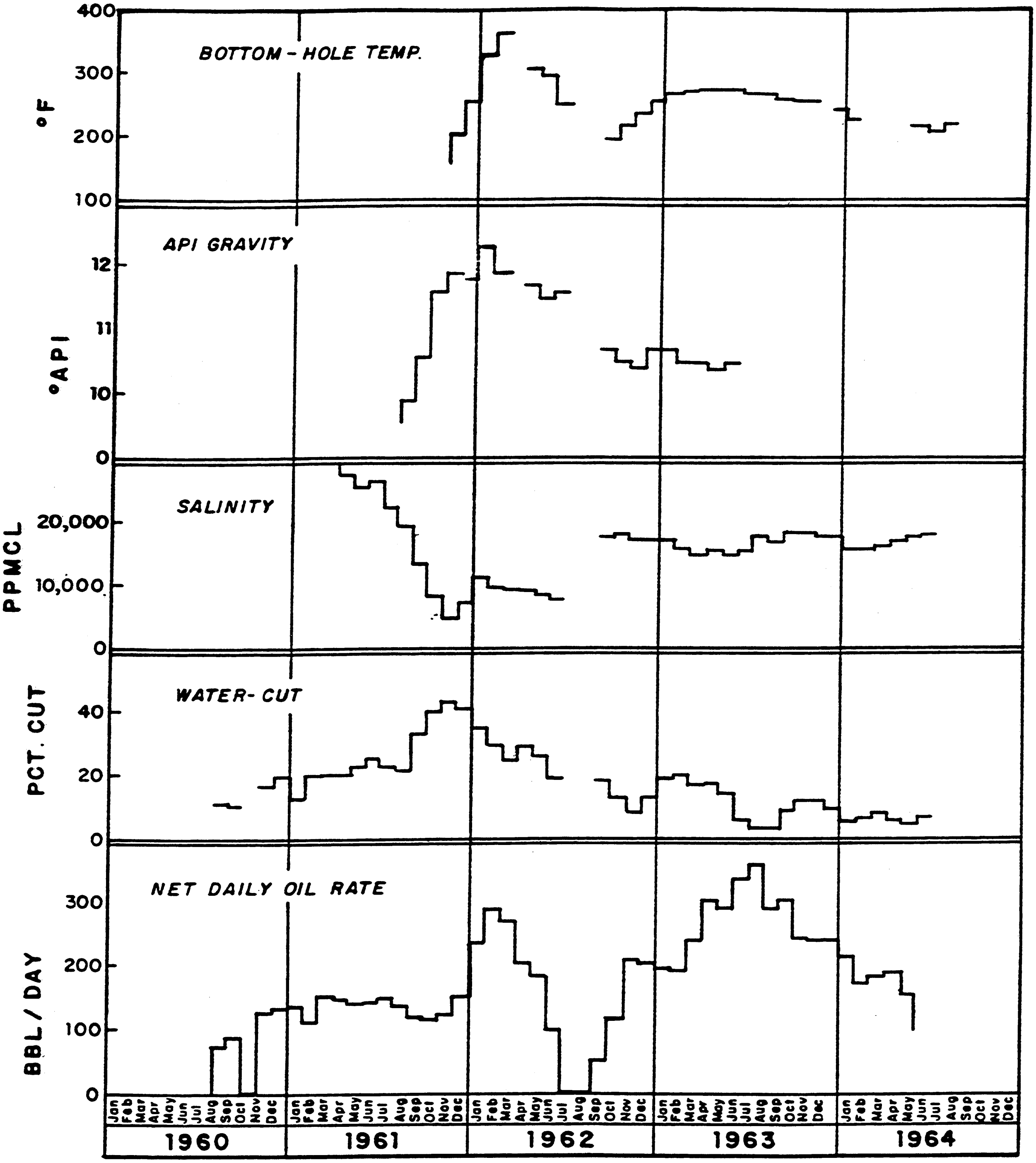


Fig. 2 TWO-SPOT COMBUSTION PROJECT NET OIL, WATER CUT. SALINITY, GRAVITY, AND TEMPERATURE VS TIME, MORICHAL FIELD.

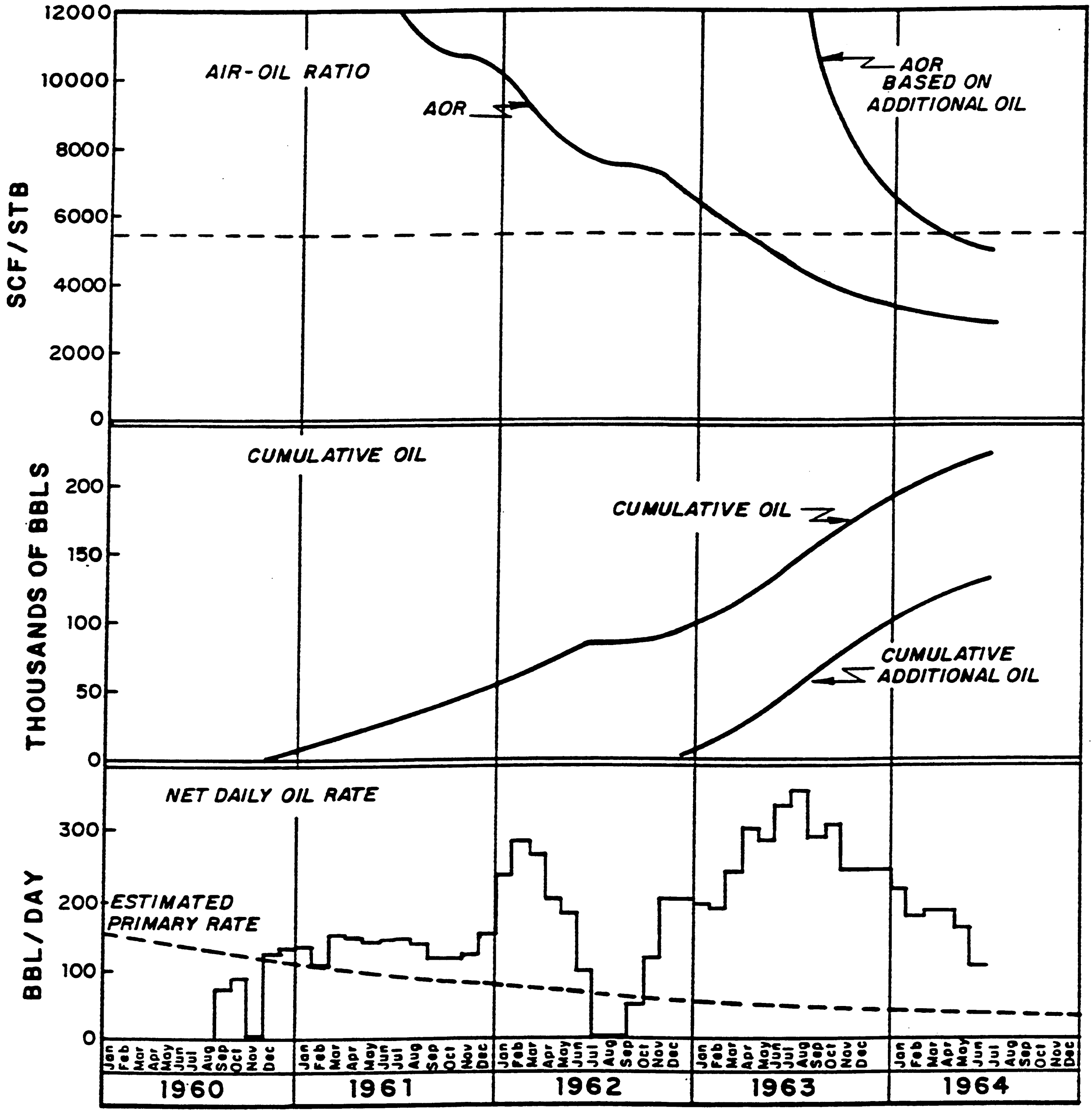


Fig. 3 TWO-SPOT COMBUSTION PROJET NET OIL, CUMULATIVE AIR-OIL RATIO VS. TIME, MORICHAL FIELD.

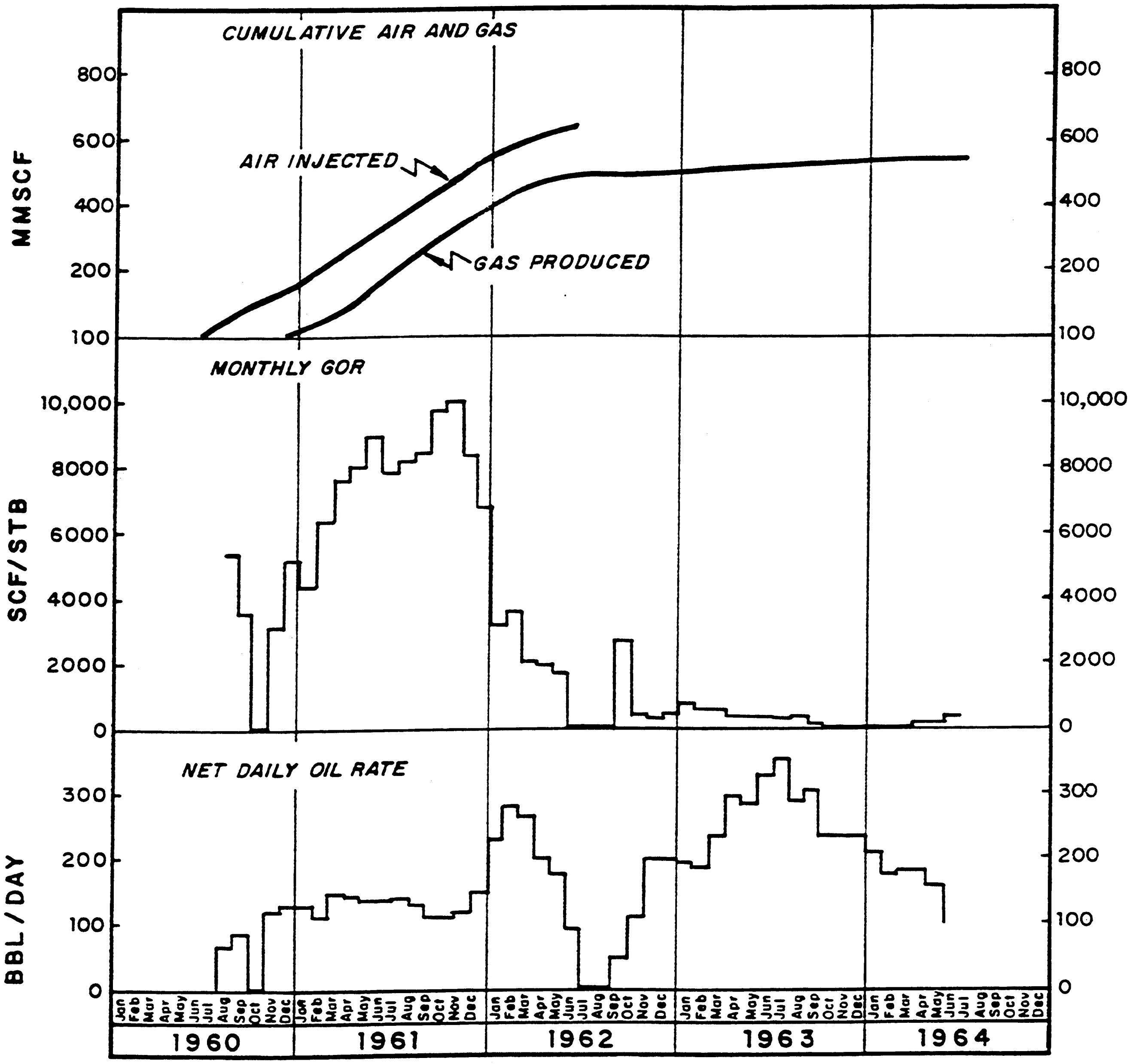


Fig. 4 TWO-SPOT COMBUSTION PROJECT NET OIL, GOR, CUMULATIVE AIR AND CUMULATIVE GAS VS. TIME, MORICHAL FIELD.

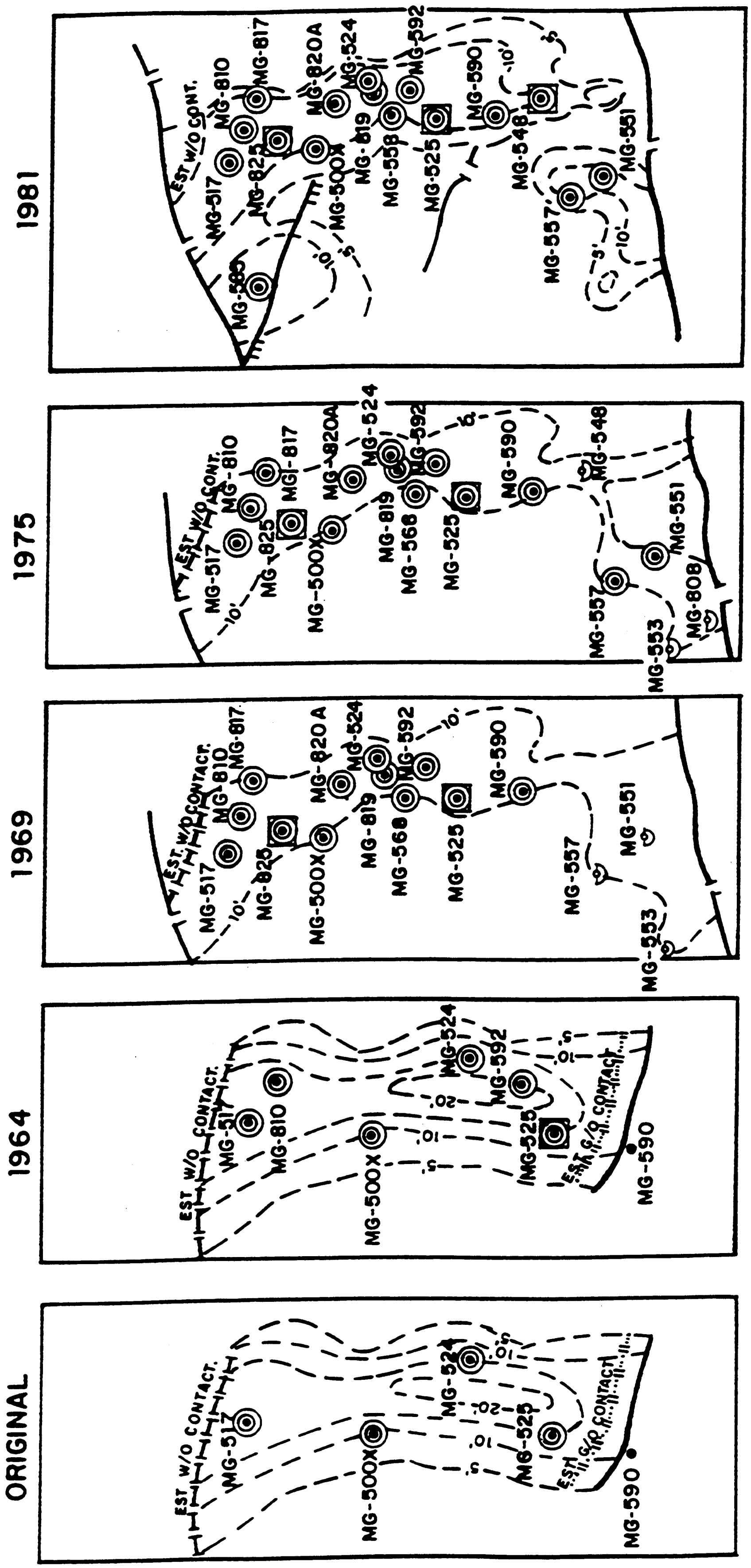


Fig.5 GEOLOGICAL INTERPRETATION OF MG-517 RESERVOIR

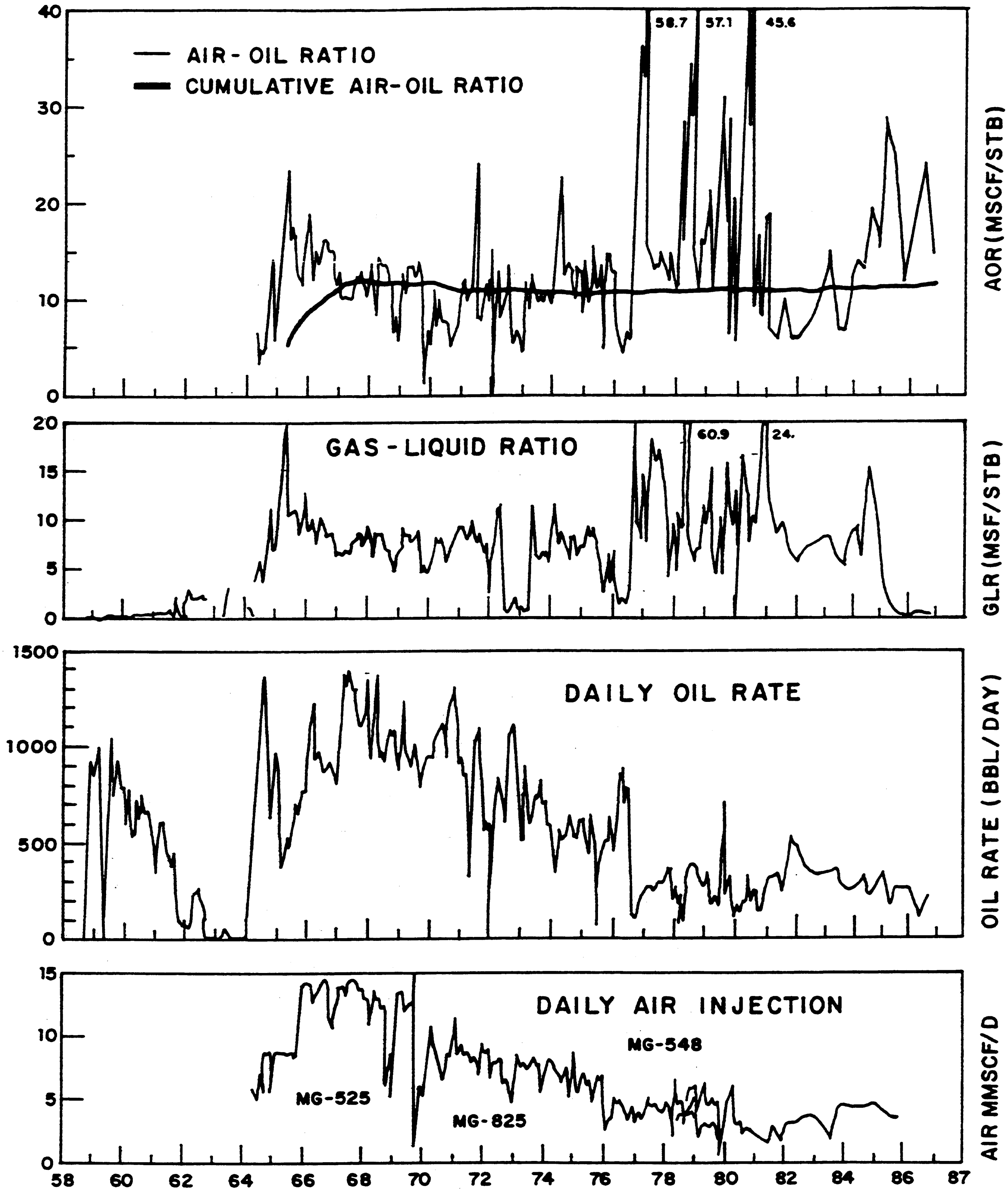


Fig. 6 PERFORMANCE HISTORY OF MIGA 517 RESERVOIR

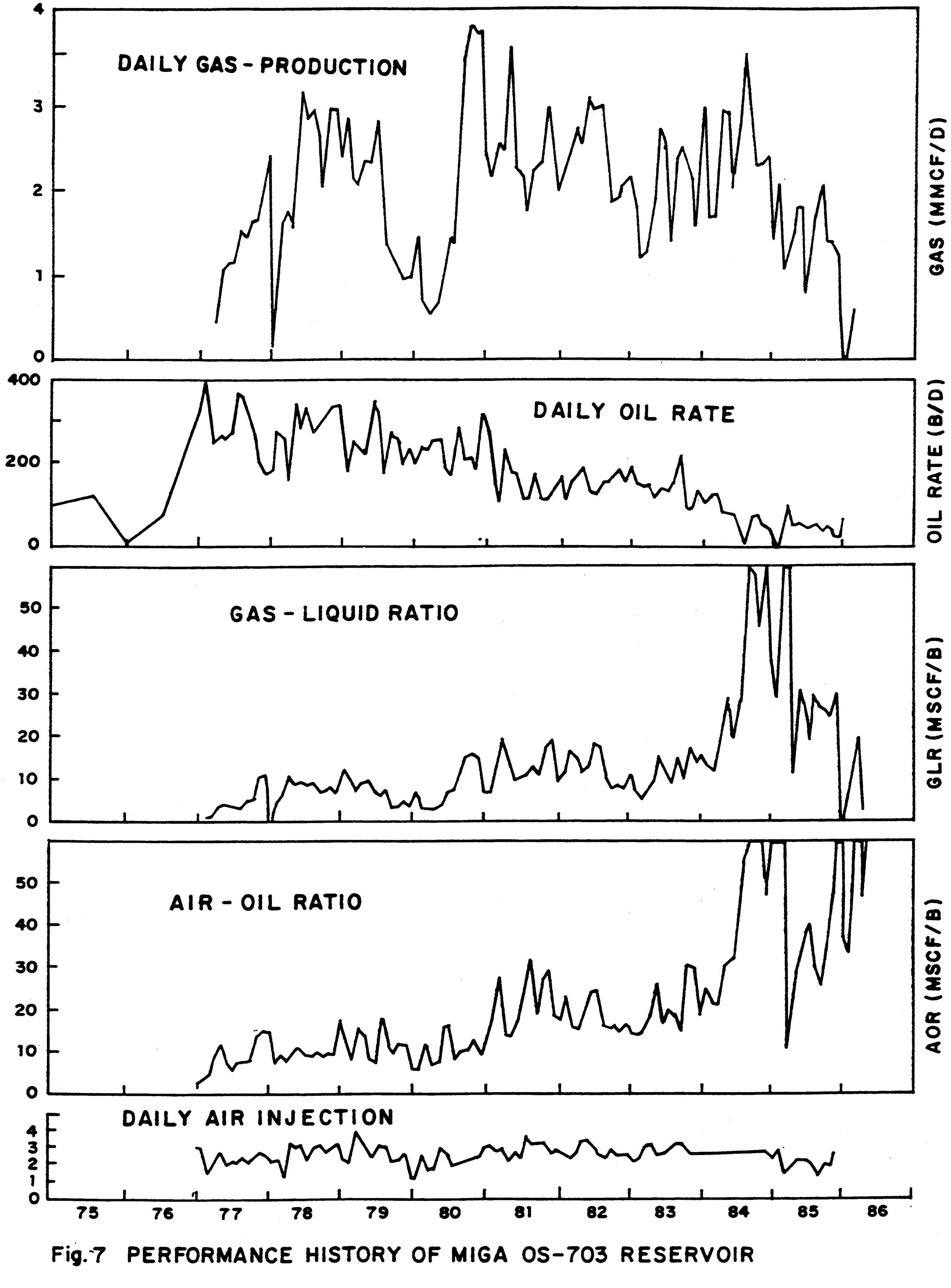


Fig. 7 PERFORMANCE HISTORY OF MIGA OS-703 RESERVOIR

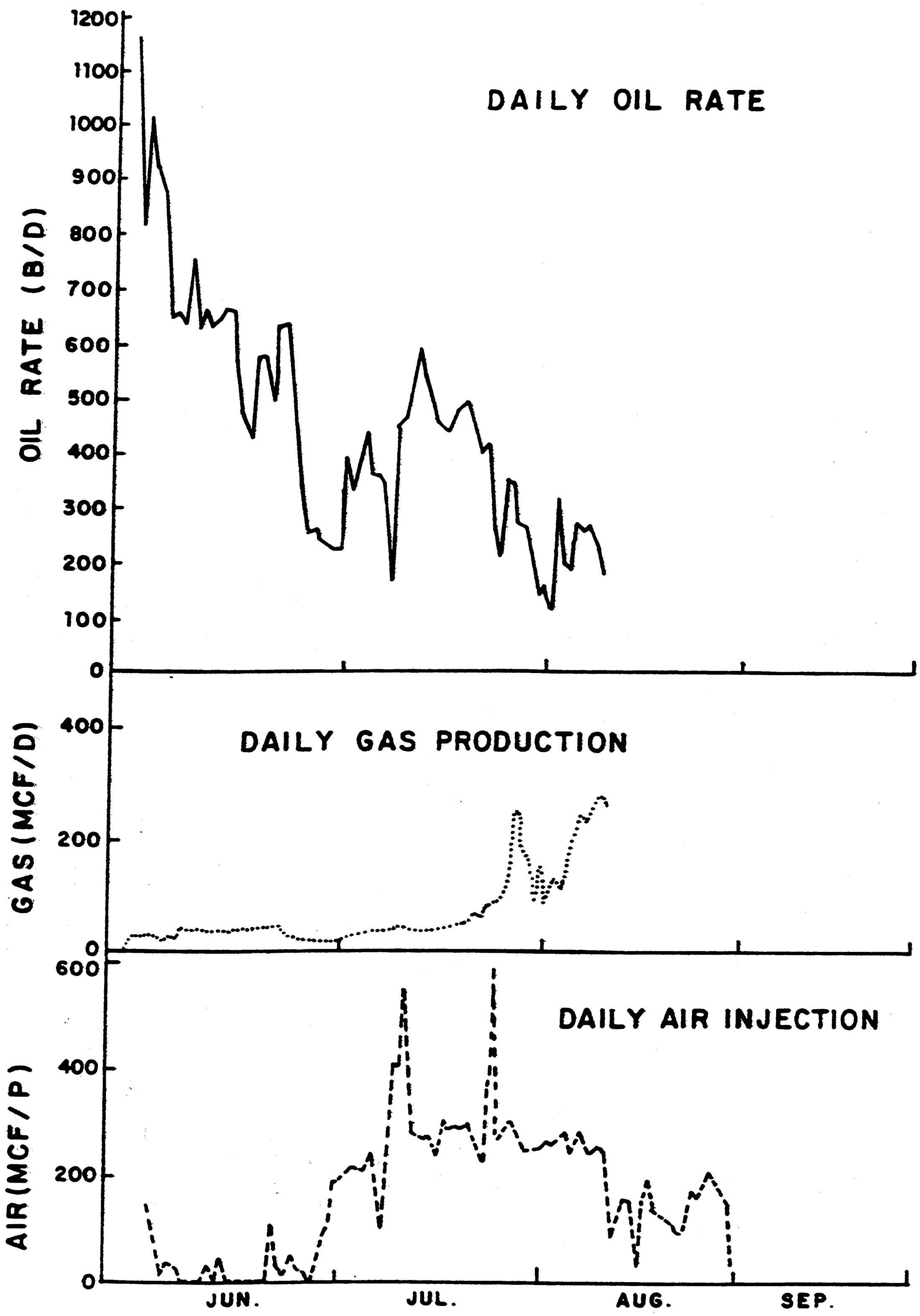


Fig. 8- TWO-SPOT WET COMBUSTION PROJECT. PERFORMANCE, MELONES FIELD.

U.C. DRIVE TEST, TIA JUANA

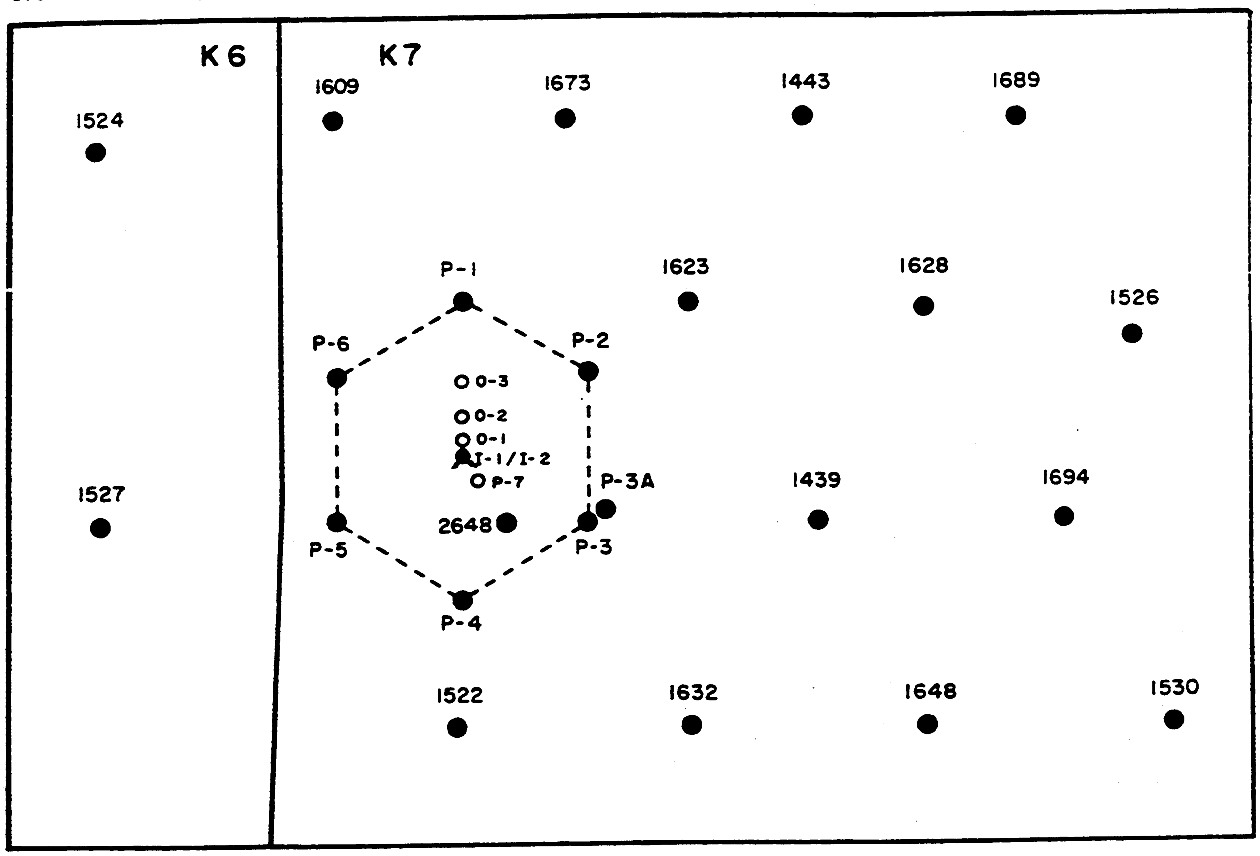


Fig.9 TIA JUANA FIELD TEST AREA.

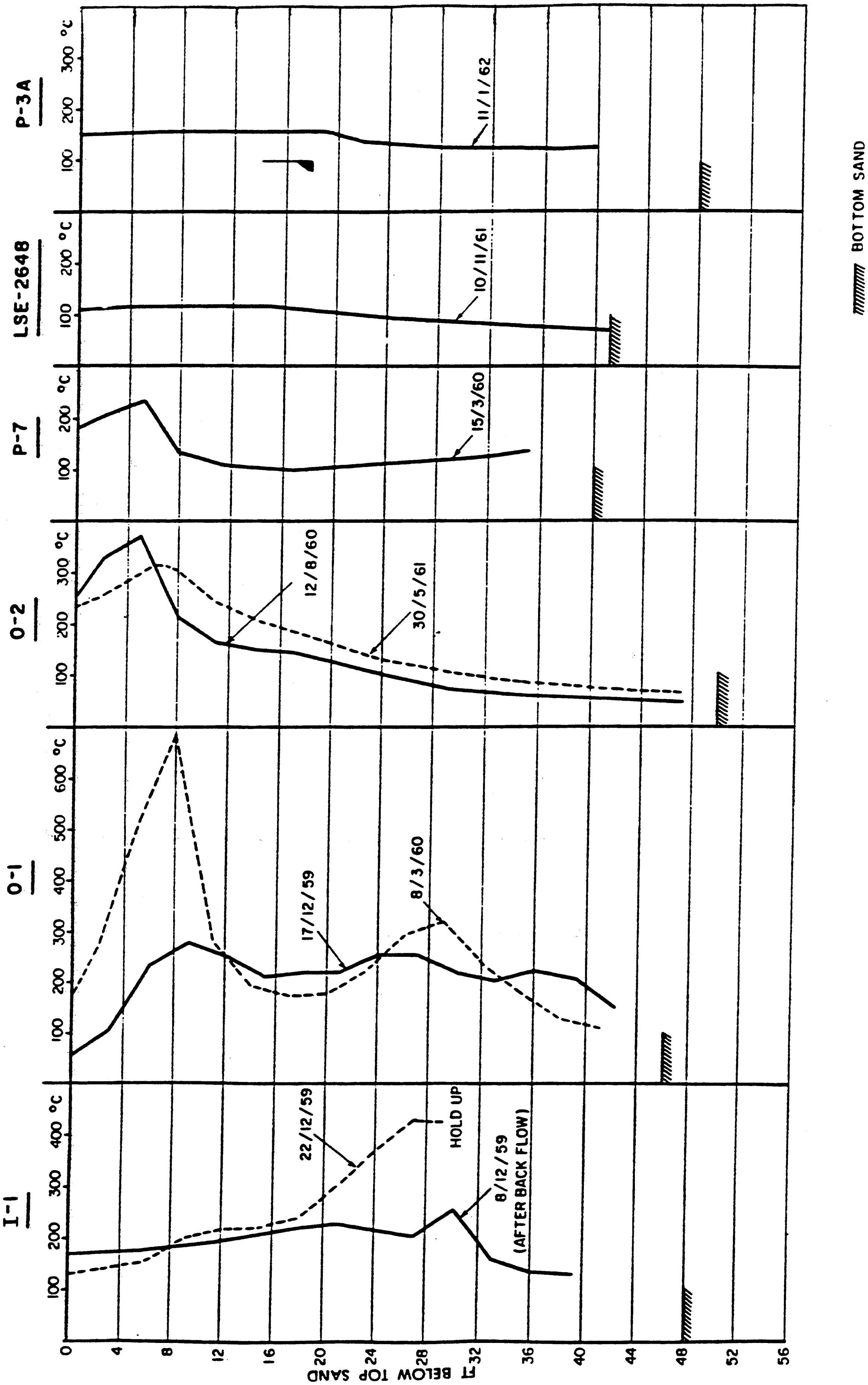
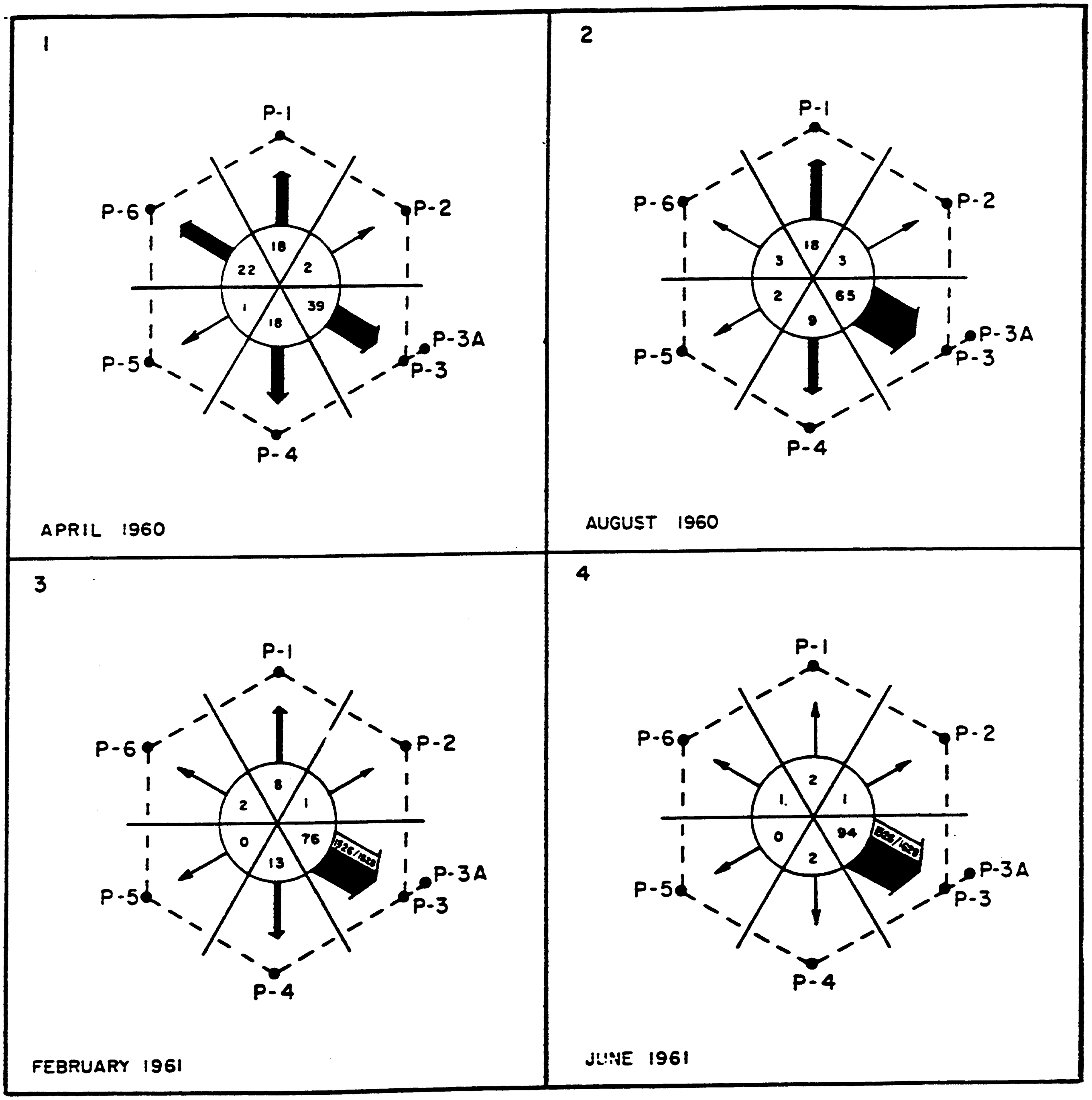


Fig.10 TEMPERATURES PROFILES IN TIA JUANA TEST.



NOTE: THE FIGURES INDICATE THE PERCENTAGE OF THE AIR INJECTED FLOWING INTO EACH SECTOR, AS DERIVED FROM GAS PRODUCTION RATES OF PATTERN AND OUTLYING WELLS.

Fig.11 DISTRIBUTION OF INJECTED AIR, AT FOUR STAGES OF THE TEST.

Romania—30 Years of Experience in In Situ Combustion

by V. Machedon, T. Popescu and R. Paduraru, Research and Design Institute for Oil and Gas, Cimpina, Romania

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

Starting with 1963, simultaneous pilot and semi-commercial steam flooding and in situ combustion tests were carried out at Suplacu de Barcău heavy oil field (16° API). The performance of in situ combustion was by far better and as a result, the entire reservoir was designed to produce by this method, by abandoning the "patterns" concept and introducing the "continuous front" concept. Under primary production, the ultimate recovery factor would have been 9.2%, while an ultimate recovery factor of at least 50% is expected by in situ combustion.

In situ combustion was applied on three other major reservoirs: Bălăria in 1975, East Videle in 1979, and West Videle in 1980. For those reservoirs, as compared to the average ultimate recovery of about 10% under primary production, an average ultimate recovery of at least 35% is expected by in situ combustion.

From an important amount of technological studies and site operations, this paper selects and presents comments and remarks related to the strategy of the field development, the "continuous front" or "patterns" system, production monitoring, difficulties encountered, etc.

References, tables and illustrations at end of paper.

In situ combustion is economically advantageous if the reservoir is carefully selected and the applied technology is of an adequate quality and suitable for the respective reservoir.

INTRODUCTION

After a fast increase—between 1950 and 1970—of the number of applied in situ combustion (I.S.C.) projects, the appeal for this method recorded an equally fast decrease, the prevailing trend becoming that of steam injection (S.I.). A careful comparison[1] of the advantages of each of these methods (I.S.C., S.I.) points out to the obvious technical superiority of I.S.C. and to equal results as regards economic profits, if the reservoirs are properly selected and the production technology is well known and properly applied.

As compared to S.I., I.S.C. means a more important engineering effort, more difficult technical, operating and control problems, more complex monitoring, more people, more equipment and hence more money; but all these could be compensated for by a higher recovery.

The basic reason for the current lack of attraction of the I.S.C. is to be found in: the low value of the current oil price, the discouragement of the operators after the failure of some projects carried out on unproperly selected reservoirs, and the higher overall effort.

1) This comparison was included in "a summary of notes" received from participants in the AOSTRA/SUPRI In Situ Combustion Forum held at Tulsa, Oklahoma, April 20-21, 1992."

The risk does not lie in the failure to use the method, but in being gradually led to the belief that the method is not worthwhile using. Such an opinion must be considered conservatively as long as there were and there still are some successfully—technically and economically—produced reservoirs, while long term studies are being carried out by famous research centres and repeated international conferences are being held, dealing—sometimes exclusively—on I.S.C.

One can but rejoice at the fact that some important scientific forums from the U.S. and Canada decided in 1992 to attempt to answer publicly and with supporting proofs to the question: "Is I.S.C. worthwhile being applied?"

I.S.C. is by no means a method to be given up from the beginning. Taking into account the huge world reserves of heavy oil and tar sands, along with ever increasing energy needs, it would only be useful having correct knowledge in this field, enabling us to apply it, if necessary. A joint research program is very likely to result in lower costs of this method.

The purpose of this paper is to present some of the ideas emerged from and used for I.S.C. developments in Romania, as well as some of their effects. The authors believe that further efforts are necessary in order to allow an even better outlining of the selection criteria for candidate reservoirs, and of I.S.C. technology and modeling.

SUPLACU DE BARCĂU

General

Suplacu de Barcău oil field (Figure 1) is located in the sandy Panonian which overlays the crystalline base (Figure 2). The average values of the reservoir main characteristics are presented in Table 1.

The reservoir was discovered in 1958 and commercial production started in 1961. The predicted production calculations showed that under primary depletion the ultimate recovery could amount to at most 9.2% during a very long time interval, with reduced daily production rates and involving high costs.[1] Due to the important amount of original oil in place, between 1961 and 1964 several studies were prepared to evaluate the possibilities for a major increase of the ultimate recovery. Those studies led to the conclusion that thermal methods can yield very satisfactory final recoveries within an acceptable and economically advantageous time interval.

Experimental Stage

In order to check the validity of the theoretical studies related to the high efficiency of thermal methods within this reservoir, steam drive (S.D.) and in situ combustion (I.S.C.) were concurrently tested in the period between 1963 and 1970. The aim was to select the most appropriate method for achieving the highest performances. Both methods were tested under similar conditions as regards the position over the structure, the area (0.5 ha) and geometry of the inverted five spot patterns (Figure 3).[2,3]

The S.D. experiment started in October 1963 within pattern I_2, while in May 1964 the I.S.C. experiment began within the pattern I_1 (Figure 3). The variation in time of typical characteristics of these two experiments is shown in Figures 4, 5.

The response of the reservoir was more favorable in the case of I.S.C.:

- total oil production from the pattern :14,812 tons during 696 days, by S.D., and 20,000 tons, during 670 days, by I.S.C.;
- the average daily production of the entire pattern was 21.3 tons by S.D. and 29.9 tons by I.S.C.;
- the average daily oil rate per well was 5.3 tons by S.D. and 7.5 tons by I.S.C.

Due to the more favorable results of I.S.C., it was decided to "cover" the initial 0.5 ha pattern by an external nine spot pattern with an area of 2 ha, maintaining the air injection in the same central well I_1 (Figure 5). Use of that external pattern yielded an incremental production of 130,000 tons of oil during 3,042 days, that is 42.7 t/d or 5.3 t/d,w. It can be noticed that as compared to the 0.5 ha pattern, using a threefold larger area (the difference up to 2 ha), a 6.5 times higher total oil production was obtained. From that fact it can be inferred that patterns with a very reduced area are not representative for assessing the technical or economic efficiency.

Within pattern I_2 an average ratio of 2.9 tons of steam/m^3 of oil, and within both (0.5 ha; 2 ha) I_1 patterns an average ratio of 2,000 Sm^3 of air/m^3 of oil were achieved.

2.3. Semi-commercial Stage

Since it became obvious that the recovery factor calculated for small areas (0.5 ha to 2 ha) was not representative, testing of both methods continued by extension to the semi-commercial stage. To this effect, the following have been achieved, (Figure 6):

- an area of 6 inverted adjacent patterns for I.S.C., located East of the initial I_1 pattern, each pattern with an area comprised between 2.5 and 4 ha;

- an area of 6 inverted adjacent patterns for S.D., located West of the combustion area, each pattern with an area of about 2 ha.

Both groups of patterns were located on the uppermost part of the reservoir, on very close isobathical positions.
Again, the results of I.S.C. were better:

- total oil production was 113,500 tons during 1,700 days (on the average 66.7 t/d or 4.6 t/d,w) for S.D., and 440,000 tons, during 4,590 days (on the average 95.8 t/d or 3.5 t/d,w) for I.S.C.;

- the ultimate recovery was 26.8% for S.D., and 40.5% for I.S.C.

Commercial Stage

The better performance of I.S.C. during the semi-commercial stage led to the decision, in 1970, to design the entire reservoir exploitation using this method. For this purpose, a preliminary production study was prepared according to the only design method available at that time- Nelson and McNiel,[4] based on inverted patterns. Following a detailed analysis of the production development by patterns system during the semi-commercial stage, a new study was worked out in which the previously called "pattern" concept was replaced by a new one, i.e., "the linear front" or "continuous front" concept.[5,6]

The detailed analysis of the production during the semi-commercial stage led to the following more important remarks:

1. The gravity effect causes a preferential air circulation from the injection well towards the upstream half of the patterns, with occurrence in numerous production wells from that area of important quantities of unconsumed oxygen; a remedy to this situation is not possible and the wells involved must be permanently shut in.

2. The gravity effect and the shut in of some wells from the upper row (West-East oriented; Figure 6) have led to reduced total productions of the wells from that row, and alternately to more important productions of the wells from the remaining two rows of the patterns. I.S.C. applied on a semi-commercial scale led to a total average production per row, as follows:

2,750 tons/well in the upper row;

11,000 tons/well in the middle row;

27,000 tons/well in the lower row (almost ten times more as compared to the upper row).

The isobathical position of a production well in respect to the injection well does obviously influence its total production.

3. The average total production of the well-lines (South-North oriented; Figure 6) that comprise one well in which the reservoir was ignited, is definitely higher than the average total production of the well-lines that do not comprise such a well, e.g.:

- within two lines of wells involving reservoir ignition, the average total production was 60,000 t/well and 32,500 t/well respectively, while

- within two lines of wells not involving reservoir ignition, the average total production was 10,500 t/well and 9.000 t/well, respectively.

4. After shut in of the wells located isobathically above the air injection well, the combustion front is merely made up of segments, propagating preferentially towards the closest depression area; thus, the volumetric displacement efficiency is rather modest.[7]

5. The volumetric displacement efficiency can be increased by turning from reservoir ignition into every second well (see middle row from Figure 6) to reservoir ignition into each well from such a row (Figure 7). This doubling of the number of combustion centres does not mean an increase of the total quantity of injected air, but an adequate distribution of the same quantity of air into the injection wells and will cause that an important additional volume of the reservoir to be directly submitted to the action of the combustion front (Figure 7).

6. It is recommendable to avoid re-entry of the oil into the pore volumes from which it was previously displaced by the combustion front; such re-entries can result in important coke deposits, in permeability reduction and in a drastic decrease of the speed of front advancement.

The remarks mentioned above have led to the decision that, for commercial production, the design prepared based on the " patterns" system be replaced by one based on the "continuous front" system.[8] The most important consequences for this replacement were:

- the use of the gravity effect with a maximum of efficiency;

- an important increase in the volumetric displacement efficiency;

- precluding oil resaturation of some pore volumes previously swept by the combustion front;

- use of the entire number of wells for production.

Of course, the working volume concerning monitoring, maintaining or adaptation of project's provisions was greater.

Essentially, turning from patterns to continuous front means:

- commencement of the production at the uppermost part, by igniting the reservoir into all wells located approximately on the same isobath, consequently forming a continuous row of air injection wells, (Figure 7);

- advancement of the combustion front downstream ;

- favoring injected air flow downstream by creation in this area, through continuous extraction, of a depression basin and by permanently shutting in the wells upstream of the air injection row and which are not used for water injection;

- turning the production wells left behind the front into air injection wells to maintain at all times the minimum distance between air injection wells and the combustion front; thus, the function of a well shifts in time from production to air injection and then possibly to water injection.

Switching from the patterns system used in the semi-commercial stage to the continuos front was completed in September 1975 (Figure 8), following which the latter was extended westwards (Figure 3). During the next years, comparisons between the efficiency of patterns production and continuous front production, at different moments in time, have pointed out to the indisputable effectiveness of the latter. For example, on July 1st, 1982:

- the reservoir volume swept by the combustion front was 76% in the area produced by continuous front, and 41.3% in that produced by patterns (Figure 8);

- the ultimate recovery was 55.2% in the area produced by continuous front and 40.5 % in that produced by patterns (Figure 9).

For detailed monitoring of the production efficiency by the continuous front (in the area located North of the semi-commercial scale production by patterns) the procedure presented in Figure 10 was adopted. By applying the procedure described in Figure 10 to the image of an actual section of the reservoir produced by I.S.C., 8 areas outlined by well rows and imaginarily separated (Figure 11) are obtained northward of the semi-commercial scale by patterns:

- taking into consideration individual rows, (Figures 11, 12), current recovery on July 1st, 1982 ranged between 59.6% within row I , the closest to the continuous front, and 26.9% within row VIII, the remotest one in respect to the continuous front;

- taking into consideration progressive sums of rows (Figures 11, 13) on July 1st, 1982, current recovery ranged between 55.8% for the sum of the first two rows and 40.5% for the sum of the eight well rows.

The recovery thus estimated is representative in a direct relation to the extent of the involved reservoir area.

The production increase as a result of switching from patterns to continuous front was obvious during the interval 1975-1976, both on the behavior diagrams for individual rows, (Figure 12), and on those for progressive sums of rows (Figure 13). The variation in time of some production features of the entire reservoir is shown in Figure 14.

By the end of 1993 [9]:

- length of the combustion front 8,900 m (29,199 ft);

- total air injection rate 3,020,000 Sm^3/d (106,650,280 scf/d);

- producers in the combustion affected area 457;

- oil production rate from the combustion affected area 1,385 t/d (9,074 bbl/d);

- average air-oil ratio (A.O.R.) 2,093 Sm^3/m^3 (11,620 scf/bbl);
- oil recovery for the entire reservoir 33 %;
- incremental production obtained by I.S.C. 9,805,000 tons (64,241,241 bbl).

An ultimate recovery of at least 50% is expected.

An important number of wells from the first two rows produced by natural flow. The overall consumed energy for production by I.S.C. stands for 25% of the overall produced energy.

The main production area is made up of the first 5...7 rows of wells parallel to the linear combustion front. Within this area, short steam injection operations are being carried out into the wells where bottomhole temperature and hence oil influx is slow to increase. The same process is applied for removing asphaltene deposits from the perforated intervals.

Due to the low thermal reactivity of the oil, ignition operations are performed using a gas burner.

The favorable results obtained at Suplacu de Barcău following switch-over to the continuous front system led, for several years, to the belief that the patterns system should no longer be applied. Yet there were some cases when reservoir engineers were compelled to reconsider the patterns system.

As other reservoirs in Romania started to produce by I.S.C., it became more and more obvious that Suplacu de Barcău is a favorable case and that only part of the conclusions reached from that case were applicable to other reservoirs, the remainder having yet to be determined as being specific to each reservoir.

At Suplacu de Barcău only one physical feature is not suitable to I.S.C., that is the depth, which at the uppermost part of the reservoir is only 35... 40 m. With a view to rapidly increase production during the period 1975-1978, the exploitation was extended, while the quantity of injected air was continuously and rapidly increased. Yet, in 1978, a crater was formed around an old well with defective cementing. The diameter of the crater increased to about 20 m. Of course, production was obviously affected (Figure 14) during the period 1978-1979, following which it started to increase and finally reached the normal value. In none of the other three reservoirs exploited by I.S.C. in Romania did this difficulty occur.

To reduce atmospheric pollution, gases are collected in a closed system up to the separation batteries from which they are released through 45 m high stacks, driven by powerful ventilators. It is planned to increase the height of the stacks and put the area under timber.

BĂLĂRIA FIELD

General

Bălăria structure, (Figure 15), was discovered in 1960 and put into production in 1963. The most important oil reserves lie within the Sarmatian 3(a+b) at West Bălăria and within the Sarmatian (3+2) at East Bălăria, (Figures 16, 17). The average values of the reservoir main characteristics are presented in Table 1.

The first studies have revealed that primary recovery could reach up to 17% at West Bălăria and up to 14% at East Bălăria after an extended exploitation.

In Situ Combustion Experiment

In 1975 a site experiment started on the Sarmatian 3(a+b) at West Bălăria, at the upper part of block II_1' in a direct five spot pattern, (Figure 15), surrounded by four inverted five spot patterns, each with the same area as that of the direct pattern. This arrangement was designed with the aim to avoid, as much as possible, external oil influx inside the direct pattern and thereby to avoid an overestimation of the I.S.C. recovery.

Ignition operations could not be achieved according to the initial program. In 1975 the reservoir was ignited only through three wells: C_1; C_2; C_4, (Figure 15). Well C_3 was damaged during the ignition operation. In 1979 other two patterns—C_5 and C_6—were added , for obtaining a direct pattern actually confined by four inverted adjacent patterns. The experiment lasted until 1982, (Figure 18). Its final evaluation, in 1983, led to the decision to design a full scale I.S.C. project for this reservoir.[10,11]

Commercial Production

Commercial production at West Bălăria started in 1984 by extension of the area of the previous experiment to the entire II'_1 block, as well as to the adjacent blocks II_1 and III_2, (Figure 15). Twenty-two I.S.C. inverted patterns were designed and carried out on these three tectonic blocks, (Figure 19). Ignition operations were carried out chemically.

By the end of 1993 the production in this area reached its final stage; 4 patterns are still operating, yielding 31.5 t/d (211 bbl/d) through 36 wells. On the same date the recovery was 31.8%. It has been estimated that at the end of I.S.C. production, the ultimate recovery factor will be 35.7%. A contribution in attaining this value will be that of water injection in the area swept by the combustion front.[12]

Starting with 1987, I.S.C. was also applied to East Bălăria, (Figure 15), the most important difference being that due to the geometry specific to this area a linear front was preferred, started at the uppermost part of the reservoir, according to the model conceived for Suplacu de Barcău. The favorable effect of I.S.C. soon became obvious, and the method proved to be efficient, (Figure 20).

By the end of 1993, at East Bălăria there were 12 air injection wells, and 66 production wells yielding 61 t/d (402 bbl/d). The current recovery factor is 23.6%. An ultimate recovery factor of at least 33.1% is estimated.[12]

The most serious difficulty consists in coke deposits in the perforations of production wells. Laboratory studies are being carried out aimed at reducing these difficulties. It seems that on metals other than steel the coke deposits are much less important.

Sometimes strong emulsioning of oil and sand inrush in the production wells occur, but these problems are generally readily solved by injecting demulsifiers through the casing, and by sand consolidation operations with quartz sand and mechanical filters.

The overall energy consumed in the process stands for 31% of the overall produced energy.

EAST VIDELE FIELD

General

Videle oil structure, one of the most important in Romania, (Figure 15), was discovered in 1959 and divided into East Videle and West Videle areas. In 1961 the Sarmatian oil reservoirs, (Figure 21), were put into production. In Table 1 are presented the average values of reservoir main characteristics. The most important reservoir is the Sarmatian 3(a+b) for which under primary depletion the ultimate recovery would have been about 7%, over a very long period.[13]

In 1973 an important water injection process started, (Figure 23). Currently, water injection is performed exclusively on the lower part of the reservoir. As I.S.C. production progresses northwards, water injection will be withdrawn to the lowest part of the reservoir.

In Situ Combustion Experiment

The pilot was an inverted and irregular eight spot pattern, with an area of about 6 ha, (Figure 15). Initiation of I.S.C. was performed using a chemical method, in March 1979, within the central well A_1, (Figure 15). The combustion front developed and progressed in a relatively uniform manner. The oil production of the A_1 pattern increased from 1.8 t/d to 10 t/d, for about 6 years, with an average A.O.R. for 4,000 Sm^3/m^3 (Figure 22).

The favorable results of the experiments carried out at Bălăria, East Videle and West Videle encouraged to proceed to the design of an I.S.C. project for the entire Sarmatian 3(a+b) reservoir.[13]

Commercial Production

The monocline shape, without steep dips and faults, made it possible to design commercial production using a linear combustion front over the entire length of the G_3 block (East-West direction) on its uppermost part. This front will progress downwards approximately parallel to the isobath, up to the lowest part of the reservoir. One row comprises at least 45 wells. The study provides for an initial stage of dry combustion, and upon formation of a front with a high displacement efficiency, for turning to a moderate wet combustion and continuing to proceed with it. In the reservoir zone swept by the front, water injection will be performed.

In July 1986, commercial production by I.S.C. started at the Sarmatian 3(a+b) reservoir, the operations for chemical ignition being performed in a progressive sequence from East towards the West, in the entire initially designed length of the combustion front. Wet combustion and water injection in the swept zone have not yet been started. The I.S.C. performances for the Sarmatian 3(a+b) reservoir are shown in Figure 23.

By the end of 1993, the oil production obtained from the I.S.C. affected zone was 79.2 t/d (530 bbl/d) from 85 wells.[14]

Difficulties:

- the slow but steady reduction of air receptivity; simple chemical treatment yields good results;

- oil emulsions; solutions are available for emulsion breaking;

- sometimes, coke deposition and blocking of tubing with shoe, or bottom pumps; in such cases, the tubing with shoe, or the pumps were raised 40-60 m above the perforations, followed by coke removal operations; studies are being carried out aimed at preventing or removing the coke depositions;

- if several production wells located as a group are simultaneously shut in for workover or repairs, gas channeling takes place towards the neighboring wells still working; the necessary remedies consist in:

a) preventive workover or repairs, according to a schedule, in order to avoid simultaneous shut in of too many wells;
b) shortening the duration of these operations as much as possible;

c) a temporary reduction—even a drastic one—of air injection in the area;

d) temporary shut in of wells with high gas rates.

The overall consumed energy stands for 37% of the overall produced energy.

WEST VIDELE FIELD

General

The heavy oil reservoirs in this zone were discovered in 1959 and put into commercial production in 1961. As compared with the total original oil in place of the West Videle zone, the Sarmatian 3(a+b) contains 74.2%, and the Sarmatian 3c, 16.8%, (Figure 24).

At the Southern part the boundary of the structure, Videle-Clejani-Bălăria major fault is also the limit of the Sarmatian 3(a+b), while the limit of the Sarmatian 3c is situated 200...300 m North of the same major fault. In other words, in the South-North direction, between the major fault and the Southern boundary of the Sarmatian 3c, one can find only the Sarmatian 3(a+b). The main physical characteristics of these two layers are presented in Table 1.

It has been estimated that primary depletion could yield an ultimate recovery factor of 9%...10% on both reservoirs, over a period of about 30 years.

During the years 1961-1966 the Sarmatian 3(a+b) was exploited due to its own energy, which comprised natural water drive; water injection started in 1966 and continues at present on a reduced scale. The effect of water injection has been acceptable and it meant a recovery factor of 20.5% in 1993.

At the Sarmatian 3c, (Figure 29), water injection started in 1974; the effect was less favorable, due to a far lower floodability of the reservoir and to a reduced productivity of the wells. Water injection on this reservoir was stopped in 1985, when the recovery factor was 12.9%, in order to proceed to commercial production by I.S.C.[7]

In Situ Combustion Experiments

In 1980 an I.S.C. experiment began on the Sarmatian 3(a+b) in the I_{1c} inverted five spot pattern, having an area of 4 ha. This pattern was operated under moderate wet combustion and production results were good, (Figure 25).

In 1984 an I.S.C. pilot test started on the Sarmatian 3c, within the 3392 inverted hexagonal pattern. The results were equally good, (Figure 26), which led to the decision to design commercial operation of both reservoirs by I.S.C.

Commercial Production

The basic ideas of the study for commercial production was the development of a linear combustion front, West-East oriented, at the uppermost part of each of the Sarmatian 3c and Sarmatian 3(a+b) reservoirs, with those two combustion fronts propagating downstream, with the same velocity and remaining parallel one to another. The first stage consisted in achieving the linear combustion front on the Sarmatian 3c, while the second stage was planned to begin after obtaining an area comprising 5...6 well rows between the position of that combustion front and the Southern limit of the Sarmatian 3(a+b); the second stage should have consisted in the formation of a combustion front on the Sarmatian 3(a+b) and its development by successive withdrawal of the wells which would progressively have entered in the swept zone of the Sarmatian 3c, (Figure 27).

In this manner, separate and simultaneous production from both reservoirs could be achieved through the same network of wells.

The production study,[15] provided for application of wet combustion and then water injection in the area swept by the front.

At the beginning of commercial production by I.S.C. on the Sarmatian 3c blocks $D_3+D_4+D_5$, the average oil rate per well was of about 0.9 t/d, with 90% water cut, and oil recovery 12.8%.

Commercial production from the Sarmatian 3c began in 1984 within block D_4, in 1985 within block D_3, and in 1986 within block D_5, (Figure 15), the ignition operations being achieved by chemical methods. Until 1989 the reservoir had been ignited through all 40 wells comprised on the Southern boundary of blocks $D_3+D_4+D_5$. After 1989 the reservoir was ignited through another 20 wells located downstream from the initial line of the front.

The actual production performance of the Sarmatian 3c differed considerably from the assumed provisions, not as much as recovery values achieved by I.S.C., but mostly as regards the pace of the front and hence, of the development. Within blocks $D_3+D_4+D_5$ up to row 8 included (Table 2) during the first 25 years of production (primary; water injection) a recovery of 17.5% was achieved, averaged to 0.7% per year, while during the next 7 years, by I.S.C., an additional recovery of 10% was obtained, averaged to 1.4% per year.[7]

To evaluate more accurately the technical efficiency of I.S.C. production of the Sarmatian 3c from the blocks $D_3+D_4+D_5$ at West Videle, the annual rates of recovery increase for three consecutive years, both prior to and after starting of I.S.C. production, have been established. As compared to the production prior to I.S.C. starting, the increase rate of oil recovery by I.S.C. was higher by 6.2 times within block D_3, (Figure 28), by 1.7 times within block D_4, by 4.2 times within block D_5, and by 2.6 times for the sum of these three tectonic blocks.

Figure 29 shows I.S.C. performances on the Sarmatian 3c within the blocks $D_3+D_4+D_5$. It can be noticed that oil production increased from about 60 t/d prior to commencement of I.S.C. (October 1984) to a maximum of about 170 t/d in September 1989, following which it constantly decreased up to 115 t/d (771 bbl/d) in December 1993. The reasons of this decline are low receptivity for air; a large volume of workover and repair operations, far larger than expected, and the impossibility to fully satisfy them; supplying difficulties; temporary shut-in of numerous air injection wells due to a technical accident on well 3824.

In order to shorten the duration of the period necessarily preceding commercial production from the Sarmatian 3(a+b), which is by far the most important reservoir on this structure, at the end of 1992 was proposed and in the first months of 1993 was decided to switch the I.S.C. on the Sarmatian 3c, blocks $D_3+D_4+D_5$, from a continuous combustion front to several parallel rows of inverted five spot patterns, simultaneously operated.[15,16] Currently, this alteration is under progress. Several preliminary ignitions carried out on the Sarmatian 3(a+b) into wells withdrawn from the Sarmatian 3c, yielded acceptable results.

By the end of 1993, an amount of 272,000 Sm^3 air /day (9,605,588 scf/d) was injected through 14 wells. The average A.O.R. is 2,370 Sm^3/m^3 (13,158 scf/bbl). The current recovery factor in the area affected by I.S.C. on the Sarmatian 3c within blocks $D_3+D_4+D_5$ is 17.4% and an ultimate recovery of about 33% is expected.[16]

The overall energy consumed in the process stands for 27% of the overall produced energy.

CONCLUSIONS

1. Four major heavy oil reservoirs are currently being exploited by I.S.C. Their total daily oil production averages to 1,670 tons (10,987 bbl).

2. Oil recovery increases from 9% to over 50% are being achieved in respect to primary production at Suplacu de Barcău, where I.S.C. stands for secondary recovery, and from 10% to at least 35% at Bălăria, East Videle and West Videle fields, where I.S.C. stands for tertiary recovery.

3. Simultaneous and separate production of two superposed strata is to be tested in West Videle field.

4. It is advisable that I.S.C. be started at the uppermost part of the reservoir, and that the first and the second stages of a possible extension be performed on a reduced scale. Correct interpretation of an important amount of data and detail remarks gathered during that stage can considerably improve production performance.

5. The linear combustion front has some important advantages as compared to patterns system. Nevertheless, the exploitation by a continuous front cannot be regarded as a general rule. The option between these two alternatives is one of the most important responsibilities of the designer.

6. Cementing quality, sand control and ignition operations are of major importance.

7. Further important efforts are necessary to improve the knowledge on I.S.C. It is very likely that such efforts be rewarded by moral and material achievements.

This paper is dedicated to HoraÆiu Dumitrescu, who introduced the thermal methods in Romania. The success of in situ combustion at Suplacu de Barcău is mainly owed to his activity both in research studies and in the field.

REFERENCES

1. Dumitrescu, H.: "Testing In Situ Combustion Process at Suplacu de Barcău Oil Field," I.C.P.T. Câmpina, 1965.
2. Dumitrescu, H.: "General Scheme of the Exploitation by Thermal Methods at Suplacu de Barcău Oil Field," I.C.P.T. Câmpina, 1966.
3. Turtă, Al: "Increasing the Direct In Situ Combustion Efficiency, Especially for Heat Transfer Intensification from Behind the Combustion Front to the Zone Ahead of It," I.C.P.T. Câmpina, 1973.
4. Nelson, T.W., and J. S. McNeil: "How to Engineer an In Situ Combustion Project," *Oil and Gas Journal*, June 5, 1961.
5. Machedon, V.: "Monitoring and Improving Wet In Situ Combustion Process at Suplacu de Barcău Oil Field," I.C.P.T. Câmpina, 1978.
6. Machedon, V.: "Reserves Study and Monitoring of Wet In Situ Combustion Process at Pliocen—Suplacu de Barcău Oil Field," I.C.P.T. Câmpina, 1982.
7. Machedon, V., T. Popescu and R. Păduraru: "Application of In Situ Combustion in Romania," Joint Canada/Romania Heavy Oil Symposium, Sinaia, Romania, Mar. 7-13, 1993.
8. Machedon, V., and M. Zamfir: "Suplacu de Barcău Field: 28 Years of In Situ Combustion," in Proceedings of the "Seventh European Symposium on Improved Recovery," Moscow, Oct. 27-29, 1993.
9. Zamfir, M.: "Exploitation Study for Suplacu de Barcău Oil Field," I.C.P.T. Câmpina, 1993.
10. Petcovici, V., and A. Panaitescu: "Exploitation Improvement at Sarmatian—Bălăria Oil Field," I.C.P.T. Câmpina, 1983.
11. Turtă, Al., and A. Panaitescu: "Monitoring and Improving of the In Situ Combustion Process at Sarmatian—Bălăria Oil Field," I.C.P.T. Câmpina, 1987.
12. Traçcă, N.: "Exploitation Study for Sarmatian—Bălăria Oil Field," I.C.P.T. Câmpina, 1993.
13. Pantazi, I.: "Exploitation Development by In Situ Combustion at East Videle Oil Field," I.C.P.T. Câmpina, 1990.
14. Perju, S.: "Exploitation Study for East Videle Oil Field," I.C.P.T. Câmpina, 1993.
15. Machedon, V., T. Popescu and R. Păduraru: "In Situ Combustion Exploitation Development at West Videle Oil Field," I.C.P.T.Câmpina, 1992.
16. Popescu, T.: "In Situ Combustion Exploitation Study for West Videle Oil Field," I.C.P.T. Câmpina, 1993.

TABLE 1
AVERAGE VALUES OF MAIN PHYSICAL CHARACTERISTICS OF CURRENT IN SITU COMBUSTION COMMERCIAL PRODUCTION DEVELOPMENTS

MAIN PHYSICAL CHARACTERISTICS	M.U.	SUPLACU DE BARCĂU FIELD	BĂLĂRIA FIELD		EAST VIDELE FIELD	WEST VIDELE FIELD	
			EAST Sa(3+2)	WEST Sa 3(a+b)		Sa 3(a+b)	Sa 3c
DEPTH	m	35 - 220	460	670	600 - 800	790	760
	ft	115 - 722	1,509	2,198	1,970 - 2,625	2,592	2,493
NET PAY THICKNESS	m	10 - 12	8	6	4.5	9	6
	ft	33 - 55	26	20	14.75	29.52	19.68
ACTUAL RESERVOIR PRESSURE	MPa	0.5 - 1.5	1.7	3	2 - 3	1.5 - 2.5	4 - 5
	psi	71.3 - 213.0	246.56	435.1	285 - 427	213 - 356	570 - 711
INITIAL RESERVOIR TEMPERATURE	°C	18	40	45	54	54	52
	°F	64	104	113	129	129	126
POROSITY	%	32	29.3	33.3	25	31.3	31.7
ACTUAL RESERVOIR SATURATION	%	75	59	56	59	61	65
ABSOLUTE PERMEABILITY	µsq.m	2	0.495	0.86	0.13	0.43	0.37
	mD	2,000	495	860	130	430	370
OIL DYNAMIC VISCOSITY, AT RESERVOIR TEMPERATURE	mPa.s	2,000	416	116	100	90	100
	cP	2,000	416	116	100	90	100
OIL DENSITY	kg/cu. m	960	955	940	940	940	940
	°API	15.89	16.66	19.03	19.03	19.03	19.03
OIL TYPE	-	asphalt base oil	asphalt base oil	asphalt base oil	asphalt base oil	asphalt base oil	asphalt base oil
RESERVOIR ROCK	-	Unconsolidated coarse, medium and fine grained sands	Sands and sandstones		Sandstones and poorly consolidated sands	Poorly consolidated and consolidated sands	Dirty and unconsolidated fine sands
DIP	Degree	5 - 8	2 - 4	2 - 5	2 - 3	2 - 4	2 - 4

TABLE 2
WEST VIDELE - SARMATIAN 3C
D3 + D4 + D5 BLOCKS
OIL RECOVERY FACTORS

SUMMED ROWS IN INCREASING SEQUENCE	OIL RECOVERY FACTOR %		
	10/1984	08/1990	12/1993
1	-	8.8	41.5
1 + 3	-	2.2	5.8
1 + 3 + 4	0.1	3.6	6.1
1 + 3 +...+ 5	10.7	14.0	15.5
1 + 3 +...+ 6	16.5	22.0	23.6
1 + 3 +...+ 7	16.7	23.4	25.1
1 + 3 +...+ 8	17.5	25.6	28.2
1 + 3 +...+ 9	14.5	21.6	24.0
1 + 3 +...+ 10	18.4	24.8	27.2
1 + 3 +...+ 11	16.1	21.6	24.0
1 + 3 +...+ 12	15.9	20.3	22.2
1 + 3 +...+ 13	14.4	18.3	20.1

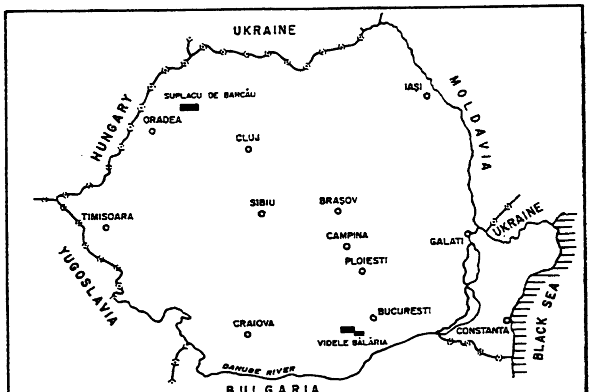


Fig. 1. SCHEMATIC MAP OF ROMANIA

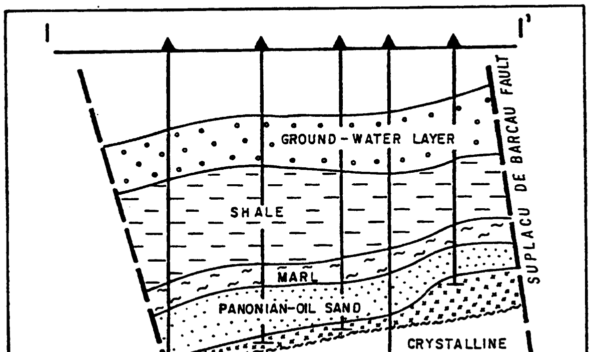


Fig. 2. PANONIAN - SUPLACU DE BARCĂU FIELD. CROSS SECTION

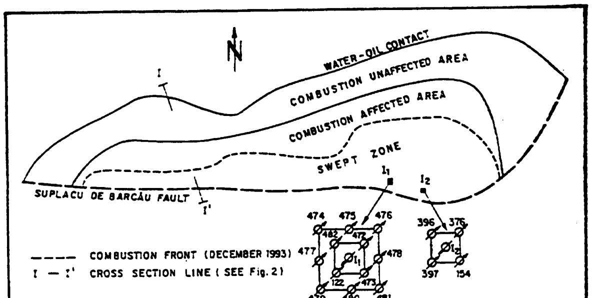


Fig. 3. PANONIAN - SUPLACU DE BARCĂU OIL FIELD. SCHEMATIC MAP

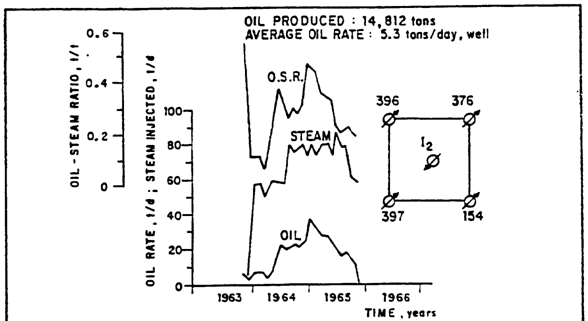


Fig. 4. SUPLACU DE BARCĂU. PILOT PATTERN I_2 STEAM FLOODING PERFORMANCE

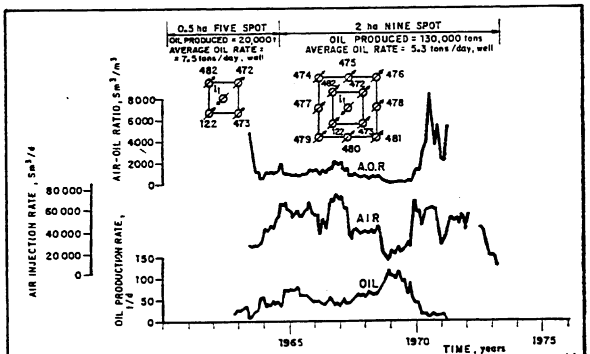


Fig. 5. SUPLACU DE BARCĂU. PILOT PATTERN I_1 IN SITU COMBUSTION PERFORMANCE

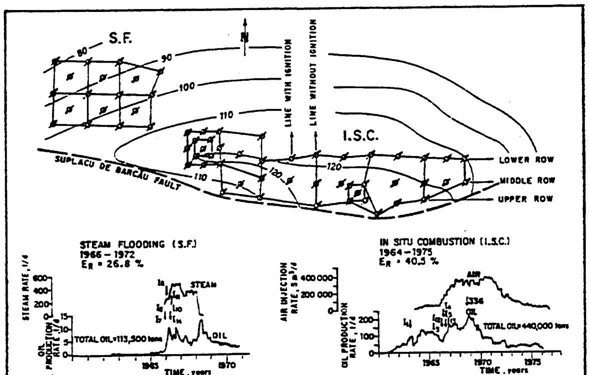


Fig. 6. SUPLACU DE BARCĂU. SEMI-COMMERCIAL APPLICATION OF THERMAL METHODS

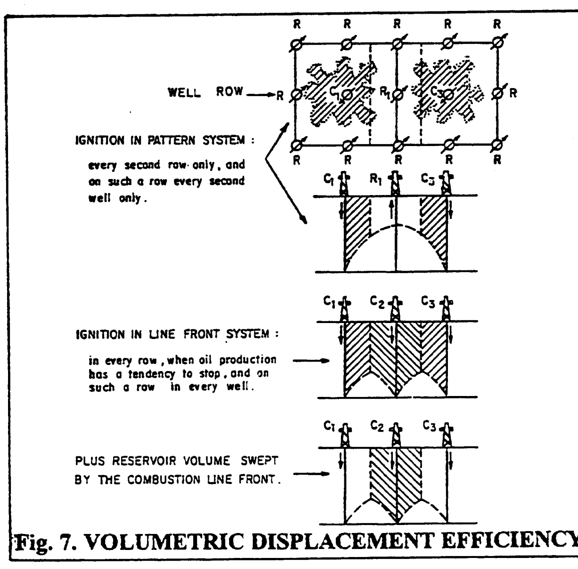


Fig. 7. VOLUMETRIC DISPLACEMENT EFFICIENCY

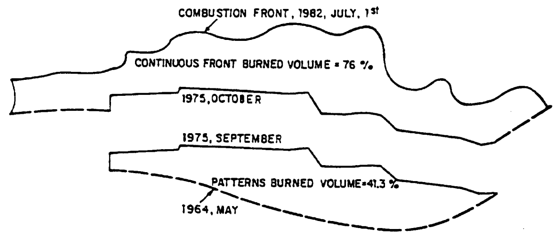


Fig. 8. SUPLACU DE BARCĂU. COMPARISON BETWEEN "PATTERNS AND CONTINUOUS FRONT" ACCORDING TO THE BURNED RESERVOIR VOLUME, 1982, JULY, 1 st

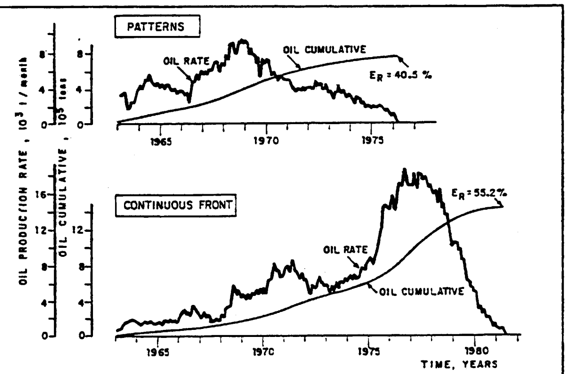
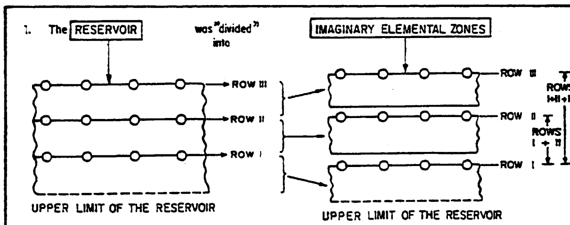


Fig. 9. SUPLACU DE BARCĂU. COMPARISON BETWEEN "PATTERNS AND CONTINUOUS FRONT" OIL RECOVERY, 1982, JULY, 1st



The elemental zones are parallel to the initial position of the continuous front.
2. Each zone is comprised between two consecutive well rows and has been considered separately in respect to the remainder of the reservoir.
3. The original oil in place was estimated for each zone.
4. It was considered that the whole oil production of a zone could be obtained only through the well row which limited downwards that zone.
5. For a certain moment:
   - the total oil production of each well row was determined;
   - the efficiency of recovery was calculated: a) for each individual rows.
     b) for progressive summed well rows.

Fig. 10. THE DETAILED MONITORING OF RECOVERY EFFICIENCY

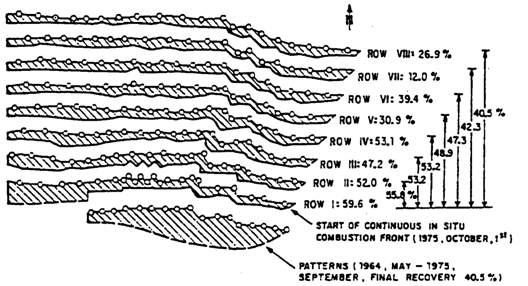


Fig. 11. SUPLACU DE BARCĂU. RECOVERY (%) FOR INDEPENDENT ROWS AND FOR SUMMED ROWS IN INCREASING SEQUENCE, 1982, JULY, 1st

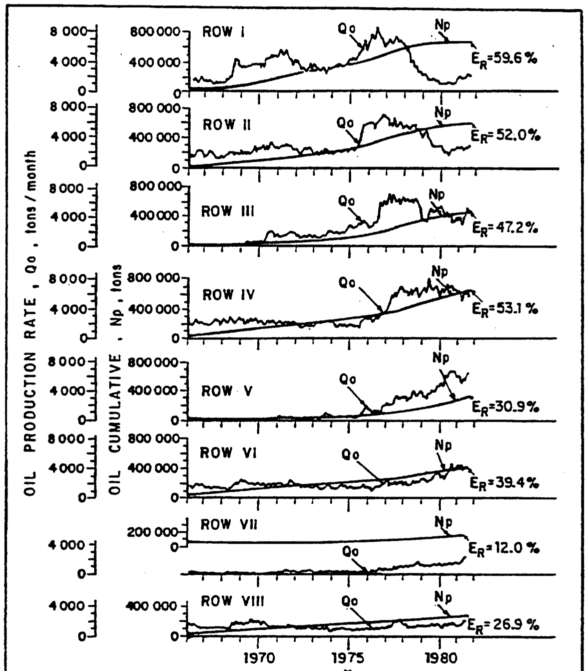


Fig. 12. SUPLACU DE BARCĂU. BEHAVIOR OF INDEPENDENT ROWS PARALLEL TO THE COMBUSTION FRONT, 1982,JULY,1st.

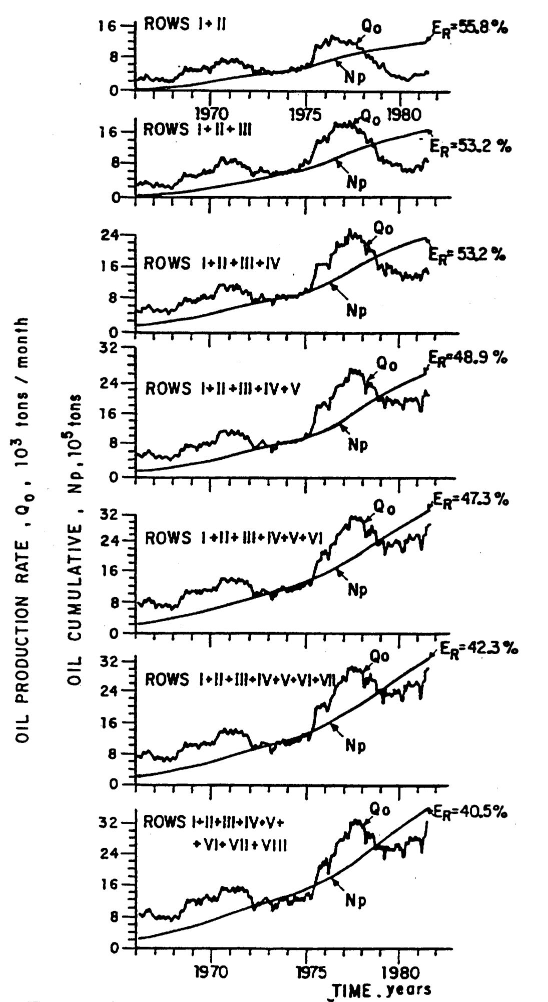


Fig. 13. SUPLACU DE BARCĂU. BEHAVIOR OF SUMMED ROWS IN INCREASING SEQUENCE, PARALLEL TO THE COMBUSTION FRONT, 1982, JULY, 1st.

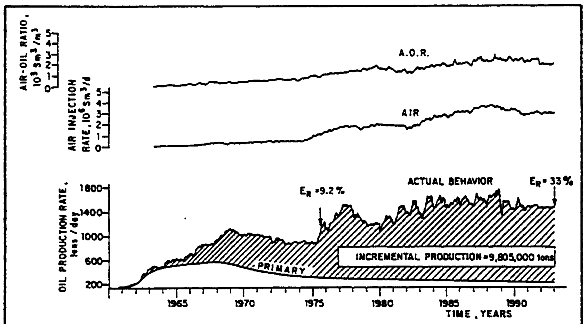


Fig.14. SUPLACU DE BARCĂU. INCREMENTAL PRODUCTION OBTAINED BY IN SITU COMBUSTION

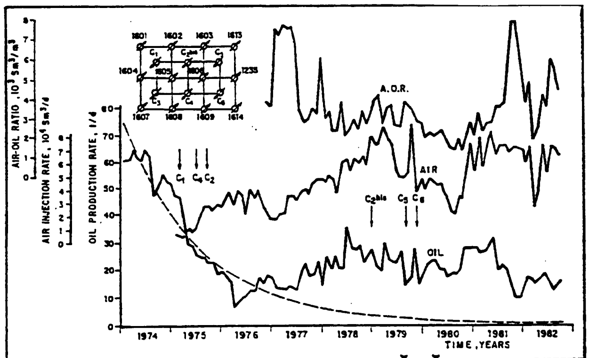


Fig.18. SARMATIAN 3(a+b) WEST BĂLĂRIA. IN SITU COMBUSTION PILOT PERFORMANCE

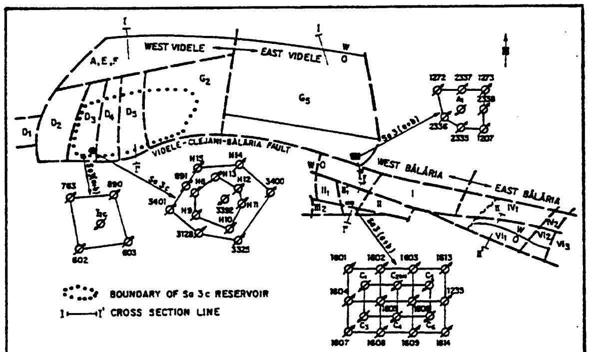


Fig.15. VIDELE - BĂLĂRIA ZONE. LOCATION OF EXPERIMENTAL IN SITU COMBUSTION PATTERNS

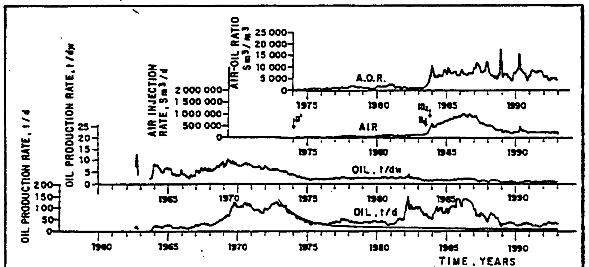


Fig.19. SARMATIAN 3(a+b) - WEST BĂLĂRIA FIELD. BLOCKS $II_1 + II_1' + III_2$. IN SITU COMBUSTION PERFORMANCE

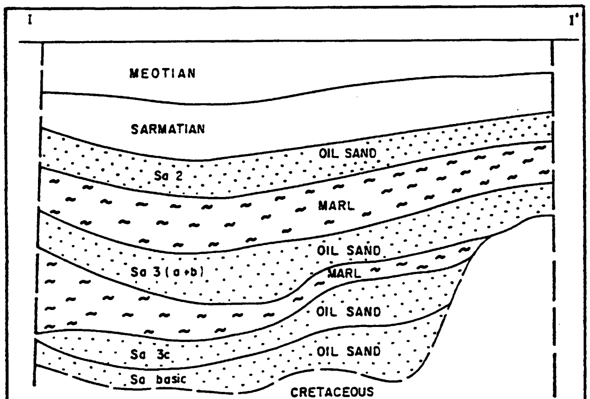


Fig.16. SARMATIAN - WEST BĂLĂRIA. CROSS SECTION

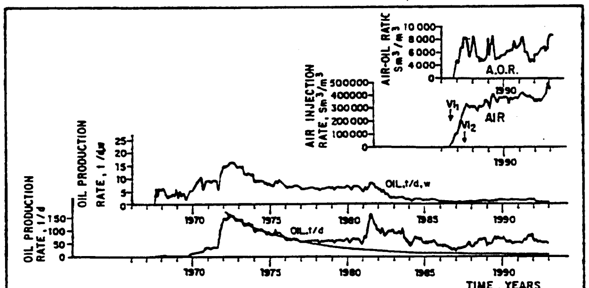


Fig.20. SARMATIAN (3+2) - EAST BĂLĂRIA FIELD. BLOCKS $VI_1 + VI_2$. IN SITU COMBUSTION PERFORMANCE

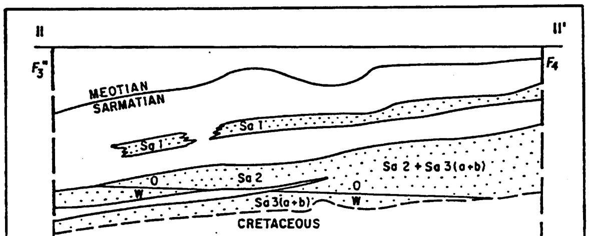


Fig.17. SARMATIAN - EAST BALARIA, CROSS SECTION

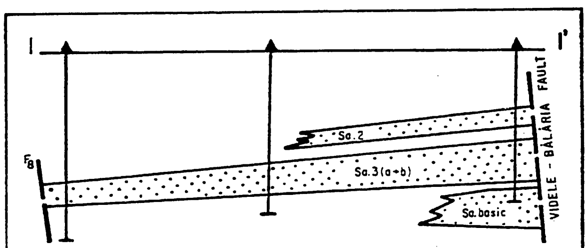


Fig.21. SARMATIAN - EAST VIDELE. CROSS SECTION

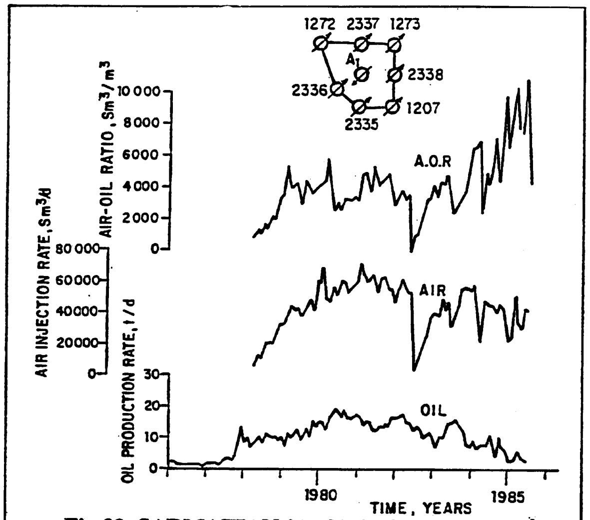


Fig.22. SARMATIAN 3(a+b) EAST VIDELE. PILOT PATTERN A_1 IN SITU COMBUSTION PERFORMANCE

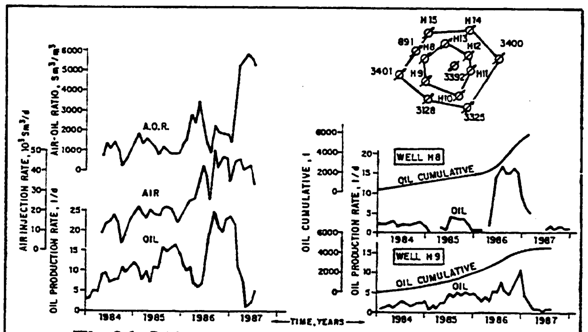


Fig.26. SARMATIAN 3c - WEST VIDELE. PILOT PATTERN 3392 IN SITU COMBUSTION PERFORMANCE

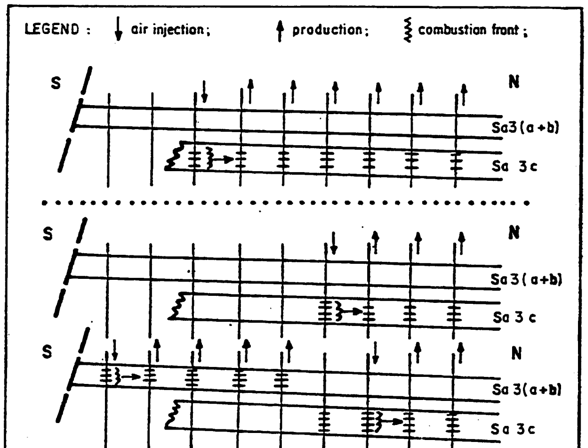


Fig.27. WEST VIDELE. SIMULTANEOUS AND SEPARATED PRODUCTION FROM Sa 3(a+b) AND Sa 3c RESERVOIRS

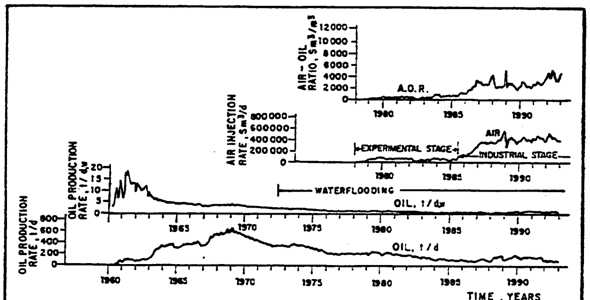


Fig.23. SARMATIAN 3(a+b) - EAST VIDELE FIELD. IN SITU COMBUSTION PERFORMANCE

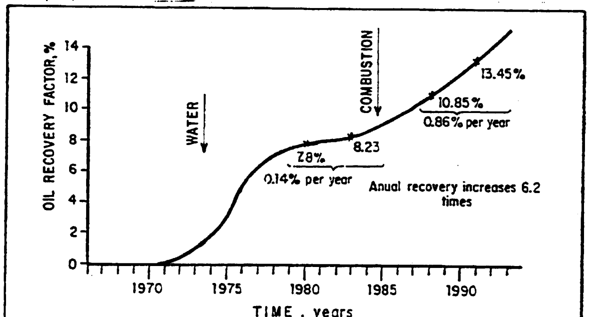


Fig.28. WEST VIDELE - SARMATIAN 3c, BLOCK D_3. VARIATION IN TIME OF THE OIL RECOVERY FACTOR

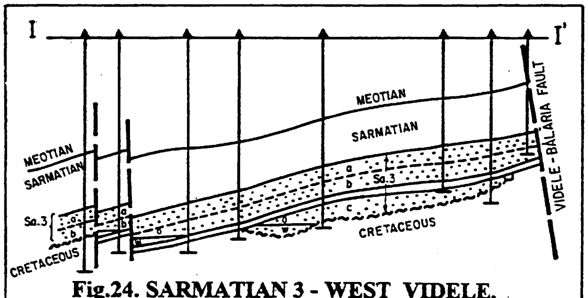


Fig.24. SARMATIAN 3 - WEST VIDELE. CROSS SECTION

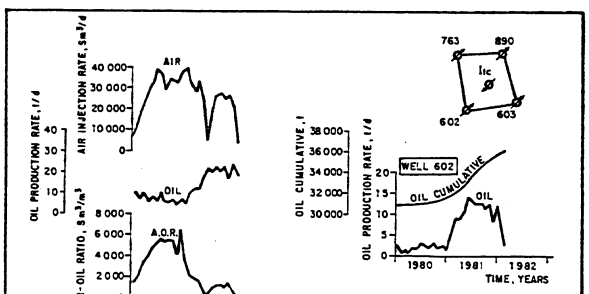


Fig.25. SARMATIAN 3(a+b) - WEST VIDELE. PILOT PATTERN I_{1c} IN SITU COMBUSTION PERFORMANCE

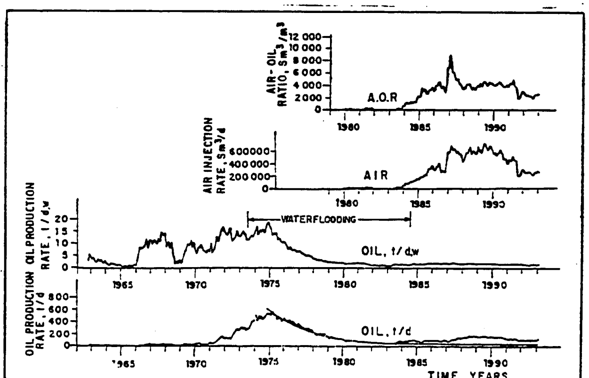


Fig.29. SARMATIAN 3c - WEST VIDELE FIELD, BLOCKS $D_3 + D_4 + D_5$. IN SITU COMBUSTION PERFORMANCE

TECHNOLOGY ASSESSMENT SESSION
DISCUSSION

Cochairs: Partha Sarathi, BDM-Oklahoma, Bartlesville, OK
Bill Richardson, Texaco

Speakers: S. M. Farouq Ali, University of Alberta, Edmonton, Canada
H. H. Gunardson, Air Products & Chemicals, Allentown, PA
A. Turta, Petroleum Recovery Institute, Calgary, Canada
P. S. Sarathi, BDM-Oklahoma, Bartlesville, OK
M. Villalba, INTEVEP, Caracas, Venezuela
V. Machedon, Research & Design Institute for Oil & Gas, Cimpina, Romania

Paper ISC-1—Redeeming Futures of In Situ Combustion

Question for Mr. Farouq Ali from Teresa McClure, Marathon Oil Co., Littleton, Colorado

If I have a reservoir that is amenable to steam, but the economics are not attractive, would you recommend combustion?

Response by Mr. Farouq Ali, University of Alberta, Edmonton, Canada

It depends on what you consider as attractive economics. If steam is not economical, then it is less likely that the combustion process will be economical, because combustion is more manpower intensive than steam and operational problems are much more severe. Further, the reservoir responds more quickly to steam than to fire, and this is one of the reasons why steam overshadowed the combustion as the preferred thermal oil recovery method.

Question for Mr. Farouq Ali from Tom Buxton, Consultant, Tulsa, Oklahoma

Do you recall why Dietz and Weijdema said that "reverse combustion is seldom feasible?"

Response by Mr. Farouq Ali, University of Alberta, Canada

The main reason they questioned the feasibility of a reverse combustion process in a reservoir was that they believed that the process will starve of oxygen, if the oxidation rate of oil under reservoir conditions is conducive to spontaneous ignition near the injection well. According to their calculation, the reverse combustion will succeed only if it receives continuous oxygen supply, and this supply is assured only if the spontaneous ignition near the injection well is delayed by a year. This is feasible only if the reservoir temperature is close to 0° C.

Paper ISC-2—Oxygen Enriched Fireflooding

Request for Mr. Gunardson from Carey Hard, Consultant, Richardson, Texas

Please comment on the economics of vacuum swing absorption process versus pressure swing absorption process for the production of oxygen at site.

Response by Mr. Gunardson, Air Products, Allentown, Pennsylvania

For a given capacity and purity, vacuum swing process consumes less power than the pressure swing process, but the vacuum swing process requires higher capital outlay.

Paper ISC-5 - In Situ Combustion Field Experience in Venezuela

Question for Miss Marlene Villaba from Partha Sarathi, BDM-Oklahoma

You said that you followed the combustion with cyclic steaming and the response was much better. Did you see any difference in response to steaming from the area that was contacted by fire and from the area that was not fireflooded?

Response by Miss Villaba, INTEVEP, Caracas, Venezuela

Since we did not compare the two responses, I cannot say for sure that one responded better than the other. From my experience, cyclic steam performs better than combustion in Venezuelan reservoirs.

Comment from Mr. Gordon Moore, University of Calgary, Canada

Since Venezuelan reservoirs are at much higher temperature, they are more susceptible to autoignition. In my opinion spontaneous ignition, more often than not, leads to LTO and poor recovery.

Paper ISC-6—Romania—30 Years of Experience in In Situ Combustion

Question for V. Machedon from Bob Horton, Texaco, Houston, Texas

Did you encounter any explosions in Romanian combustion projects?

Response by V. Machedon

Yes, we had four or five explosions that resulted in equipment damage, but no loss of life.

Question for V. Machedon from John Dillon, BP Exploration, Anchorage, Alaska

What was the well spacing in your projects?

Response by V. Machedon, Institute for Research and Technology, Prahova, Romania

We started with 200 meters spacing between wells, but reduced it to 50 to improve capture efficiency. In Romania, the cost of drilling is very low and one can afford to drill at very close spacing.

No. ISC 7

DOE/NIPER

The Effect of Low-Temperature Oxidation on the Fuel and Produced Oil During In Situ Combustion

by D. D. Mamora of Texas A&M University, College Station, Texas, and W. E. Brigham of Stanford University, Stanford, California

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

Combustion tube experiments using 10.2° API crude oil were performed, in which a different sample matrix was used in each run. Three matrix types were tested: sand, sand and clay, and sand and sand fines. As a result of the low fuel concentration, low-temperature oxidation (LTO) was observed in the run where the matrix consisted of sand only. High-temperature oxidation (HTO) was observed in runs where either clay or sand fines were part of the matrix. Ignition was not obtained in the LTO run, which had a reaction front temperature of only 350° C (662° F), compared to a combustion front temperature of 500° C (932° F) for the HTO runs. From elemental analysis, the fuel during the LTO run was determined to be an oxygenated hydrocarbon with an atomic oxygen-carbon ratio of 0.3.

A method was derived to estimate heats of reaction for oxygenated fuels. The estimated heat of reaction of the fuel for the LTO run was about half that for an unoxygenated fuel. The LTO reaction front traveled slower (8 cm/hr) compared to the HTO combustion front velocity of 11 cm/hr for the same air flux. The viscosities of the produced oil from the HTO runs were significantly reduced from 14,000 cP to as low as 260 cP, while that from the LTO run increased slightly to 17,000 cP. An increase in oil gravity of 1°-4° API in the produced oil was observed for the HTO runs, while the produced oil gravity decreased slightly to 9.8°API in the LTO run.

The study concludes that LTO is a highly inefficient process. Before starting a combustion project, it is critical to run combustion tube experiments, using oil and core samples and fluid saturations representative of the field, to determine which oxidation reaction type will occur.

References, tables and illustrations at end of paper.

INTRODUCTION

Dry, forward in-situ combustion may be described by a simple chain reaction consisting of two competitive steps: fuel deposition and fuel combustion.[1-3] A third reaction, low-temperature oxidation (LTO), may occur, if oxygen is present downstream of the combustion front.

Fuel Deposition

Fuel deposition is the process of leaving fuel on the reservoir matrix. The amount of fuel deposited, or fuel concentration, is an important parameter in in-situ combustion project design. The maximum oil recovery is the difference between the initial oil-in-place and the amount of fuel consumed. A high fuel concentration will reduce the combustion front velocity and increase air requirements, which will result in higher air compression costs. On the other hand, if the fuel concentration is too low, combustion heat generated may be insufficient to propagate a self-sustaining combustion.

Analyses of core samples from South Belridge indicated reservoir lithology to be an important parameter for fuel deposition.[4] Based on kinetic experiments, Bousaid and Ramey[1] showed that the amount of fuel deposited increased with the addition of clay to the sample of oil and sand.

Alexander *et al.*[5] performed flood-pot experiments, and found that the amount of fuel deposited increased with initial oil saturation, oil viscosity and the Conradson residue, and decreased with increasing atomic hydrogen-carbon ratio and API gravity of the oil. Showalter[6] carried out combustion tube experiments, and found results similar to those of Alexander *et al.*, and that the amount of fuel deposited increased with decreasing API gravity of the oil.

Thermogravimetric studies were performed by Bae[7] for a wide range of crude oil gravities (6°-38° API). One of the conclusions of the study is that the main mechanism for fuel deposition is distillation.

Poetmann *et al.*[8] concluded from their studies that the specific area of the porous medium is an important parameter for fuel deposition, particularly for high-gravity, paraffin base crude oils. Results of combustion tube experiments performed by Vossoughi *et al.*[9] indicate that clay particles increase the amount of fuel deposited.

Fuel Combustion

The hydrocarbon fuel, CH_x, deposited at the combustion zone reacts with injected oxygen to generate heat for the combustion process. Based on the experimental studies of Benham and Poettmann,[10] the stochiometry of hydrocarbon fuel combustion may be described by Eq. 1.

$$CH_x + \left(1 - \frac{m}{2} + \frac{x}{4}\right)O_2 \rightarrow (1-m)CO_2 + mCO + \frac{x}{2}H_2O \quad (1)$$

where x is the atomic hydrogen-carbon (H/C) ratio of the fuel, and m is the m-ratio (fraction of carbon oxidized to carbon monoxide).

Several researchers studied the effect of fuel concentration, C_f, and the rate of oxygen consumption on the combustion front velocity, V_F.[10-14] The results may be described by Eq. 2.[12]

$$V_F = \frac{U}{C_f R_{af}} \quad (2)$$

where U is the air flux at the combustion front, and R_{af} is the air-fuel ratio.

In combustion and kinetic tube experiments, the atomic hydrogen-carbon and m-ratios of the fuel may be determined from analysis of the effluent gas. If CO_2 and CO are the mole percent of carbon dioxide and carbon monoxide respectively in the produced gas, the m-ratio is given by Eq. 3.

$$m = \frac{CO}{(CO + CO_2)} \quad (3)$$

Let O_{2p} and N_2 denote the mole percent of oxygen and nitrogen respectively in the effluent gas. The mole percent of oxygen consumed, O_{2c}, may be obtained from a nitrogen material balance and is given by Eq. 4.

$$O_{2c} = 0.2682 N_2 - O_{2p} \quad (4)$$

Based on an oxygen material balance, and using Eq. 4, the apparent atomic hydrogen-carbon ratio, x, can be calculated:

$$x = 4\frac{\left[0.2682 N_2 - \left(O_{2p} + CO_2 + 0.5CO\right)\right]}{\left(CO_2 + CO\right)} \quad (5)$$

Low-Temperature Oxidation

Low-temperature oxidation (LTO) of crude oil occurs at temperatures less than about 650°F (345°C). The reaction is exothermic and is characterized by the production of little or no carbonoxides. The main products of LTO are oxygenated compounds such as carboxylic acids, aldehydes, ketones, alcohols and hyperoxides.[15]

To investigate the effect of LTO on fuel formation, Alexander *et al.*[5] subjected a sample of oil and sand to a continuous injection of air and a heating schedule. A coke-like residue was deposited on the sand matrix as a result of prolonged LTO reactions. For a 21.8° API crude oil, the amount of residue increased to a maximum at about 425° C (218° F) and decreased sharply to zero at about 650°F (345° C). The apparent atomic hydrogen-carbon ratio decreased from about 50 at 250° F (121° C) to about 1 at 650° F (345° C). The large apparent atomic hydrogen-carbon ratio is a result of oxygen being consumed in LTO reactions which do not produce carbon oxides. The viscosity and boiling range of the crude oil were increased due to LTO. Alexander *et al.* concluded that LTO reactions have a pronounced effect on fuel deposition and composition. Crude oils generally increase in total weight as a result of LTO.[7]

Crawford[16] found that aldehydes promote LTO reactions. Certain metallic additives and soils have a catalytic effect on LTO reactions.[1,9,16,17] The LTO reaction rate was found to be proportional to the matrix specific area raised to a power between 0 and 1.[15,18] Dabbous and Fulton concluded that during LTO, oxygen diffusion into the oil phase is greater than the oxidation reaction rate, so that oxygen is dissolved throughout the oil phase during LTO.

Several investigators have used the heat released during LTO to estimate the spontaneous ignition time for an in-situ combustion project.[4,19,20] Light crude oils were found to be more susceptible to LTO than heavy crude oils.[18]

This paper describes the combustion tube experiments which were carried out to investigate the factors that cause low-temperature oxidation and its effect on the combustion process and properties of the produced oil.

EXPERIMENTAL APPARATUS AND PROCEDURE

Figure 1 is a schematic diagram of the apparatus, which is set up to run either kinetic or combustion tube experiments. Major equipment, such as the gas analyzers, gas chromatograph, and the data acquisition unit, are shared between the two types of experiments, to minimize redundancy and cost of the apparatus.[21] A description of the apparatus and procedure for combustion tube experiments only will be given.

Air was supplied from pressurized gas cylinders and injected at the top of the combustion tube, which was placed in a vertical position. Air injection rate and pressure were kept constant by means of the mass flow controller and the back-pressure regulator. Produced fluids passed through a condenser coil in an ice-cooled water bath to cool and remove fluids from the produced stream. Further liquid removal was made in the separators. Water was removed from the produced gas by passing the gas through a trap containing Drierite (anhydrous calcium sulfate). A tube containing Purafil II Chemisorbant was placed at the inlet of the oxygen analyzer to remove any acid in the gas stream. The produced gas passed through three gas analyzers and a gas chromatograph, where the concentrations of carbon dioxide, carbon monoxide, oxygen and nitrogen were measured. The personal computer was programmed to record, at 30-sec intervals, the gas analyzer readings; injected gas rate and pressure; produced gas rate; and to compute and record nitrogen concentration data at six minute intervals.

The combustion tube consisted of a thin-walled stainless steel tube measuring 39 in. long × 3 in. O.D. × 0.016 in. wall thickness (Fig. 2). Knife-edge flanges were silver soldered to both ends of the tube. A 9 in. long × 1 in. I.D. brass tube was silver soldered to the top flange. A pair of 1/8 in. and 1/16 in. Swagelok tube fittings was silver soldered to the top of the brass tube, through which two thermowells passed and were secured. The thermowells consisted of a pair of 1/8 in and a 1/16 in. stainless steel tubes about 94 cm long, silver soldered at several places along the length. A bundle of nine thermocouples (each of 0.020 in. I.D.) were silver soldered with the tips spaced at 10 cm intervals. This thermocouple bundle was inserted in the larger thermowell, and recorded temperatures at known positions in the tube. A thermocouple of 0.030 in O.D. was placed in the smaller thermowell. This thermocouple could be moved freely to measure temperatures in small traverse increments. The combustion tube was sealed by a system of copper gaskets between the flanges, and Teflon twin ferrules at the thermowell-tube fitting connections. An electric ignitor was wound around the tube about 10 cm from the top flange.

Three different matrix types were used in the experiments: (1) 20-30 mesh sand with 4.6% by weight of clay, (2) 20-30 mesh sand, and (3) 20-30 mesh sand and 4.6% by weight of 170-270 mesh sand fines (Table 1). For direct comparison of results of the tube runs, the same 10.2° API Venezuela crude was used, and the air injection rate and pressure were kept at 3 L/min and 100 psig.

Almost from the start, water was produced, while oil was produced after about 4 to 5 hours. Produced liquids were collected in graduated sample bottles which were tightly sealed for subsequent analysis. The sand pack was burned to the bottom, so that the amount of fuel burned could be determined accurately. Each tube run took about 8 to 10 hours. After each run, the produced fluids were analyzed to determine the volumes of oil and water, the produced oil API gravity, and the produced oil viscosity as a function of temperature using a Brookfield viscometer.

DISCUSSION OF RESULTS

The results of the combustion tube runs are summarized in Table 2. A brief description of each tube run follows.

Run VEN5

The sample matrix consisted of sand and clay. Stable combustion was observed from the start of the run, as indicated by the stable produced gas composition readings (Fig. 3). Based on gas analysis, apparent H/C and m-ratios were calculated, as shown in Fig. 4. In the period 1-7.5 hours, the average H/C ratio is 1.63, compared to 1.65 for the original crude, as determined from elemental analysis. This result indicates the absence of low-temperature oxidation and the predominance of distillation as the fuel deposition mechanism. The average combustion temperature was 500° C (Fig. 5). Produced oil gravity at the end of the run was 3.8° API higher than that of the original crude (Fig. 6). The average combustion front velocity was 10.5 cm/hr (0.35 ft/hr). The viscosity of the produced oil decreased from the crude oil original value of 14,000 cP at 50° C to 260 cP (Fig. 7).

Run VEN14

The sample matrix consisted of sand only. The electric heater was left on for two hours into the run to aid ignition. However, ignition was not obtained. This run was a low-temperature burn, as indicated by the temperature and gas analysis data. In the period 3-9 hours, the produced gas molar concentrations were: CO_2, 4.3 %; CO, 2.0 %; O_2, 10.1 % and N_2, 82.8% (Fig. 8). The average apparent H/C and m-ratios were 4.35 and 0.312 (Fig. 9). The high apparent H/C ratio is a result of low-temperature oxidation, during which oxygen enters reactions which do not form carbon oxides. The average temperature at the reaction zone was 350° C (Fig. 10). Figure 11 indicates a reaction front velocity of 7.7 cm/hr (0.25 ft/hr), significantly lower than that in Run VEN5. Produced oil gravity and viscosity data are shown in Figs. 11 and 12, respectively. Produced oil gravity, 9.8° API, was slightly lower than that of the original crude oil, while the oil viscosity increased slightly to 17,000 cP at 50° C from the original crude oil value of 14,000 cP. The decrease in oil gravity and increase in oil viscosity were due to low-temperature oxidation. Alexander et al.[5] also found an increase in the viscosity of oil which had undergone low-temperature oxidation. Bae[7] also observed a decrease in the API gravity of oil subjected to low-temperature oxidation.

An estimate of the percent of oxygen used in LTO may be calculated using Eq. 6.[22]

Percent of oxygen in LTO

$$= \frac{100\left(x_{apparent} - x_{true}\right)\left(CO_2 + CO\right)}{4\left(0.2682N_2 - O_{2p}\right)} \qquad (6)$$

Based on Eq. 6, 35% of oxygen injected went into LTO and 46% of oxygen injected was produced and did not generate heat. Thus, only 19% entered into HTO reactions. A material balance on oil indicated 43% was deposited as an immobile residue and 57% was displaced with little or no improvement in quality. Elemental analysis of a produced oil sample from this run indicated an atomic oxygen-carbon ratio of 0.25.

Run VEN21

The sample matrix was made up of sand and sand fines. Despite the absence of clay in the matrix, a fairly stable burn was obtained, although the produced gas readings were rather oscillatory. In the period 1-7 hours, the produced gas molar concentrations were: CO_2, 9.7%: CO, 4.3%; O_2, 3.8% and N_2, 81.2% (Fig. 13). Apparent H/C and *m*-ratios averaged 1.77 and 0.308, respectively (Fig. 14). The average combustion front temperature and velocity were 500° C and 11.1 cm/hr (0.36 ft/hr), respectively (Figs. 15 and 16). The gravity of the produced oil increased by 1° API (Fig. 16), while the oil viscosity decreased to 2,600 cP at 50° C from 14,000 cP for the original crude oil (Fig. 17).

The results of this run were very similar to that of Run VEN5 (in which clay was included in the sample), except for the oscillatory gas composition readings. Vossoughi *et al.*[9] inferred from combustion tube experiments that clay did not have a catalytic effect on combustion. A possible effect of clay and the sand fines is as follows. Both clay and the 170-270 mesh sand particles are smaller than those of 20-30 mesh sand. These smaller particles most likely increase oil entrapment and thereby increase fuel concentration. Oil entrapment may be caused by permeability reduction and the greater surface area of these particles. Similarly, fuel concentration is decreased when the sample does not contain clay or sand fines, which may lead to low-temperature oxidation, as observed in Run VEN14.

HEAT OF COMBUSTION OF OXYGENATED FUEL

For a hydrocarbon fuel (CH_x) which undergoes combustion according to the stochiometry given by Eq. 1, the heat of reaction, ΔH_x, is estimated using Eq. 7.[15] It is assumed in Eq. 7 that the products of combustion are gaseous carbon dioxide and carbon monoxide and condensed water.

$$\Delta H_x = \frac{1800}{(12+x)}(94.0 - 67.9m + 31.2x) \qquad (7)$$

For an oxygenated hydrocarbon fuel (CH_xO_y), the heat of combustion is considerably less than that for a hydrocarbon fuel, on a per unit mass basis, since an oxygenated fuel is partially oxidized and also its mass includes oxygen. The heat of combustion of an oxygenated hydrocarbon was estimated by considering the fuel oxidation paths as indicated in Fig. 18. In Fig. 18, Path A is the oxidation of a hydrocarbon fuel to form carbon oxides and water. Path B represents the oxygenation of the fuel to form CH_xO_y, while Path C is the oxidation of the oxygenated fuel to form carbon oxides and water.

Let ΔH_A be the heat of reaction per mole of oxygen consumed for Path A, and let ΔH_B, and ΔH_C be the heats of reaction for Paths B and C for the same mass of fuel as in Path A. ΔH_A (KJ/mol O_2) may be calculated from Eq. 8.[15]

$$\Delta H_A = \frac{786.4 - 567.6m + 260.9x}{2 - m + 0.5x} \qquad (8)$$

The heats of reactions (KJ/mol O_2) for the main products of hydrocarbon oxygenation are as follows:[15] carboxylic acid (430.8), aldehyde (363.1), ketone (375.7) and alcohol or phenol (306.6). The averaged heat of reaction for these oxygenated products is 369.0 KJ/mol O_2. For one mole of oxygen consumed for Path A, the number of moles of oxygen consumed for Path B is $(y/2)(1 - m/2 + x/4)$. Therefore:

$$\Delta H_B = \frac{369.0y}{2(1 - 0.5m + 0.25x)} \qquad (9)$$

From conservation of energy:

$$\Delta H_C = \Delta H_A - \Delta H_B \qquad (10)$$

Using Eqs. 8, 9 and 10:

$$\frac{\Delta H_C}{\Delta H_A} = 1 - \frac{369.0y}{786.4 - 567.6m + 260.9x} \qquad (11)$$

Let R_m denote the molar mass ratio of CH_x to CH_xO_y:

$$R_m = \frac{12+x}{12+x+16y} \tag{12}$$

The heat of reaction for an oxygenated fuel, ΔH_{xy} (Btu/lb of oxygenated fuel), is proportional to ΔH_x but reduced by the heat of oxygenation and by the addition of oxygen to the fuel mass. That is:

$$\Delta H_{xy} = \frac{\Delta H_C}{\Delta H_A} R_m \Delta H_x \tag{13}$$

Substituting Eqs. 7, 11 and 12 into Eq. 13:

$$\Delta H_{xy} = \frac{1800(94.0-67.9m+31.2x)}{(12+x+16y)} \times \left[1-\frac{369.0y}{(786.4-567.6m+260.9x)}\right] \tag{14}$$

Using Eq. 14, the heat of combustion for an oxygenated hydrocarbon was computed as a function of atomic H/C, O/C and m-ratios. The results are presented in Fig. 19. The heat of combustion decreases significantly with increasing atomic O/C ratio, and also decreases slightly with increasing m-ratio for typical m-ratio ranges. For example, for a fuel with an atomic H/C ratio of 1.5 and m-ratio of 0.3, the heat of combustion decreases from 16,000 Btu/lb fuel, for an atomic O/C ratio of 0.0, down to 8,000 Btu/lb fuel for an atomic O/C ratio of 0.5. Therefore, if the fuel is oxygenated as a result of low-temperature oxidation, an inefficient combustion process will occur. For the same reason, oxygenated gasoline used in automobiles will give considerably lower mileage per gallon than non-oxygenated gasolines.

CONCLUSIONS

1. High combustion temperatures were obtained when clay or sand fines were present. These particles reduced the permeability of the sand pack and also provided a large reaction surface area. Consequently, the residual oil saturation, and therefore the fuel concentration, increased, resulting in high temperature burns. Practically all the injected oxygen was consumed at the combustion zone. Hence, hydrocarbons ahead of the combustion front did not undergo low-temperature oxidation. This resulted in atomic H/C ratios which were similar to those of the original crude oils. The viscosity of the produced oil was reduced significantly, while the produced oil gravity increased by 1°-4° API.
2. In contrast, low-temperature oxidation occurred when the sample matrix contained only 20-30 mesh sand. Ignition was not obtained due to the low fuel concentration, and a significant amount of oxygen moved ahead of the combustion zone. This resulted in low-temperature oxidation of the crude oil to form an oxygenated hydrocarbon. Low-temperature oxidation was found to be a very inefficient process, both from the standpoint of oxygen usage and heat generated. In addition, the resulting oxygenated crude viscosity increased significantly.
3. Before starting a combustion project, it is essential to run combustion tube experiments, using oil and core samples and fluid saturations representative of the field, to ascertain that low-temperature oxidation will not occur.

ACKNOWLEDGMENT

We like to dedicate this paper to our co-worker and friend, the late Dr. Henry J. Ramey, Jr., whose contribution to this research is invaluable. It is our great privilege to have known and worked with such a tireless, devoted, and unselfish engineer.

REFERENCES

1. Bousaid, I. S., and H. J. Ramey Jr.: "Oxidation of Crude Oil in Porous Media," *SPEJ,* June 1968, pp. 137-148.
2. Dabbous, M. K., and P. F. Fulton: "Low-Temperature Oxidation Reaction Kinetics and Effects on the In-Situ Combustion Process," *SPEJ* , June 1974, pp. 253-262.
3. Thomas, G. W., A. P. Buthod and O. Allag: "An Experimental Study of the Kinetics of Dry, Forward Combustion-Final Report," Report No. BETC-1820-1, distributed by Dept. of Energy, February 1979.
4. Gates, G. F., and H. J. Ramey Jr.: "A Method of Engineering In-Situ Combustion Oil-Recovery Projects," *JPT* , February 1980, pp. 285-294.
5. Alexander, J. D., W. L. Martin and J. N. Dew: "Factors Affecting Fuel Availability and Composition During In-Situ Combustion," JPT, October 1962, pp. 1154-1164.
6. Showalter, W. E.: "Combustion Drive Tests," *SPEJ,* March 1963, pp. 53-58.
7. Bae, J. H.: "Characterization of Crude Oil for Fireflooding Using Thermal Analysis Methods," *SPEJ,* June 1977, pp. 211-217.
8. Poettmann, F. H., R. E. Schilson and H. Surkalo: "Philosophy and Technology of In-Situ Combustion in Light Oil Reservoirs," Proc. of the Seventh World Pet. Congress, Mexico City, 1967, III, p. 487.
9. Vossoughi, S., G. P. Willhite, W. P. Krikitos, I. M. Guvenir and Y. El Shoubary: "Automation of an In-Situ Combustion Tube and Study of the Effect of Clay on the In-Situ Combustion Process," *SPEJ,* August 1982, pp. 493-502.

10. Benham, A. L., and F. H. Poettmann: "The Thermal Recovery Process-An Analysis of Laboratory Combustion Data," *Trans., AIME,* 1958, **213**, pp. 406-408.
11. Martin, W. L., J. D. Alexander J. N. and J. N. Dew: "Process Variables of In-Situ Combustion," *Trans., AIME*, 1958, **213**, pp. 28-35.
12. Penberthy, W. L. Jr., and H. J. Ramey Jr.: "Design and Operation of Laboratory Combustion Tubes," *SPEJ,* June 1966, pp. 183-198.
13. Moss, J. T., P. D. White and J. S. McNeil Jr.: "In-Situ Combustion Process—Results of a Five-Well Field Experiment in Southern Oklahoma," *JPT,* April 1959, pp. 55-64.
14. Wilson, L. A., R. L. Reed, D. W. Reed, R. R. Clay and N. H. Harrison: "Some Effects of Pressure on Forward and Reverse Combustion," *SPEJ*, September 1963, pp. 127-137.
15. Burger, J. G. and B. C. Sahuquet: "Chemical Aspects of In-Situ Combustion—Heat of Combustion and Kinetics," *SPEJ*, October 1972, pp. 410-422.
16. Crawford, P. B.: "Water Technology—Underground Combustion of Hydrocarbons," *Producers' Monthly,* June 1968, p. 15.
17. Johnson, H. R., and E. L. Burwell: "Carbon Deposition for Thermal Recovery of Petroleum—A Statistical Approach to Research," *Producers' Monthly,* July 1968, p. 8-15.
18. Dabbous, M. K., and P. F. Fulton: "Low-Temperature Oxidation Reaction Kinetics and Effects on the In-Situ Combustion Process," *SPEJ* , June 1974, pp. 253-262.
19. Tadema, H. J., and J. Weijdema: "Spontaneous Ignition in Oil Sands," *Oil and Gas Journal,* December 1970, pp. 77-80.
20. Burger, J. G.: "Spontaneous Ignition in Oil Reservoirs," *SPEJ,* April 1976, pp. 73-81.
21. Mamora, D. D.: "*Kinetics of In-Situ Combustion*," PhD dissertation, Stanford University, Stanford, CA, May 1993.
22. Ramey, H. J. Jr., V. W. Stamp, F. N. Pebdani and J. E. Mallinson: "Case History of South Belridge, California, In-Situ Combustion Oil Recovery," paper SPE 24200 presented at the SPE/DOE Eight Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 21-24, 1992.

TABLE 1

Properties of Sand Packs

	Run No.		
	VEN5	VEN14	VEN21
Oil gravity (°API)	10.2	10.2	10.2
Oil viscosity at 50°C (cP)	14,000	14,000	14,000
Length (cm)	85.4	87.1	85.4
Weight (g)	7,739	7,461	7,447
Oil (wt. %)	4.6	4.9	4.6
Water (wt. %)	4.1	4.3	4.1
20-30 mesh sand (wt. %)	86.8	90.8	86.8
Clay (wt. %)	4.6	0	0
170-270 mesh sand (wt. %)	0	0	4.6
S_o (fraction of pore vol.)	0.29	0.26	0.26
S_w (fraction of pore vol.)	0.27	0.23	0.24
S_g (fraction of pore vol.)	0.44	0.51	0.50
ϕ (fraction of bulk vol.)	0.31	0.35	0.33

TABLE 2

Combustion Tube Experimental Results

	Run No.		
	VEN5	VEN14	VEN21
Injection pressure (psig)	100	100	100
Injection rate (L/min)	3.00	3.00	3.00
Air flux (scf/hr-sq. ft.)	130.9	130.9	130.9
Comb. front temp. (°C)	500	350	500
Comb. front velocity (cm/hr)	10.5	7.7	11.1
Produced liquids:			
Oil gravity (°API)	14.0	9.8	11.2
Oil viscosity at 50°C (cP)	260	17,000	2600
Produced water vol. (ml)	353	285	271
Produced oil vol. (ml)	287	346	298
Oil recovery (wt. %)	78	94	88
Produced gas:			
Ave. prod. rate (L/min)	2.80	2.55	3.05
CO_2 (mole %)	11.6	4.3	9.7
CO (mole %)	4.9	2.0	4.3
O_2 (mole %)	1.1	10.1	3.8
N_2 (mole %)	81.4	82.8	81.2
Calculated results:			
m-ratio	0.298	0.312	0.308
Apparent H/C ratio	1.63	4.35	1.77
Residue after burn (g)	28.7	143.9	8.6
Fuel conc. (lb/ft^3 bulk vol.)	0.784	-	0.539
O2 utilization efficiency (%)	95.0	54.5	82.6
Air-fuel ratio (scf/lb fuel)	167	-	169
Air req'ments (scf/ft^3)	139	-	112
Heat of comb. (Btu/lb fuel)	16,458	-	16,773

1. Air filter
2. Mass flow controller
3. Pressure transducer
4. Kinetic cell
5. Electric furnace
6. Combustion tube
7. Pressure jacket
8. Separator
9. Water pump
10. Condenser
11. Separator
12. Drierite tube
13. Micro filter
14. Gas flow meter
15. Back-pressure regulator
16. Rotameter
17. Pressure relief valve
18. Acid scrubber
19. Gas auto-sampler
20. Gas chromatograph
21. Carbon dioxide analyzer
22. Carbon monoxide analyzer
23. Oxygen analyzer
24. Vent manifold

Valve

2-way valve

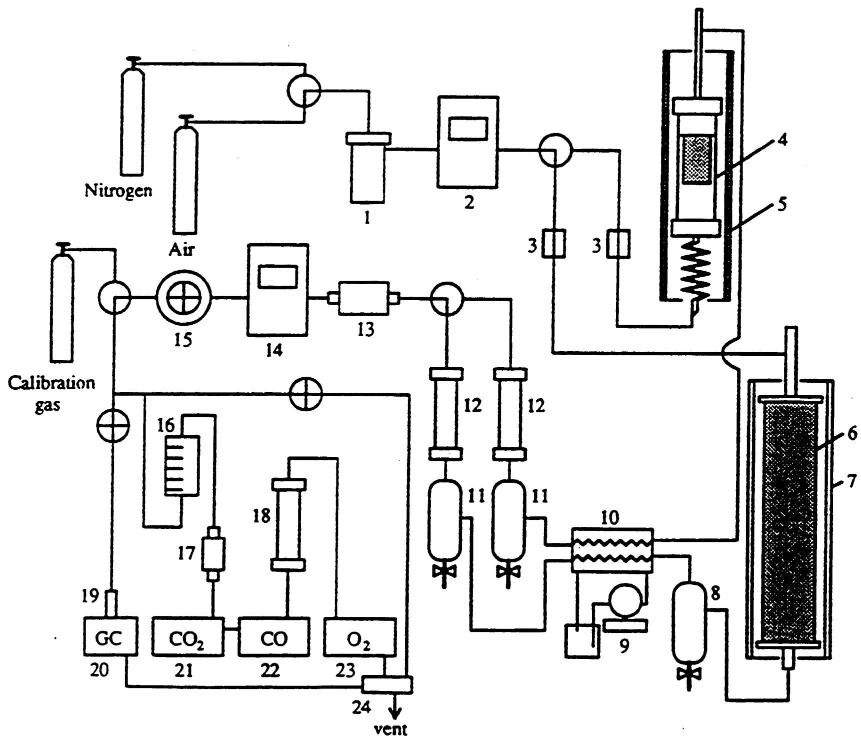


Fig. 1 - Schematic Diagram of Kinetic and Combustion Tube Apparatus

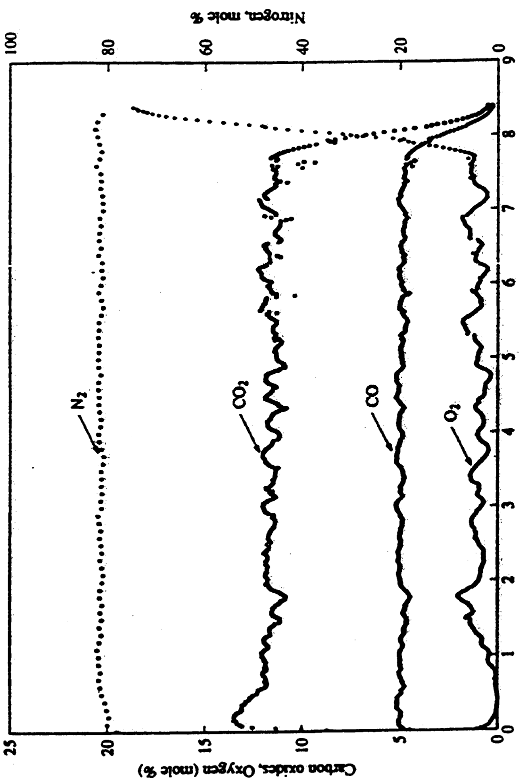


Fig. 3 - Produced Gas Composition Versus Temperature (Run VEN5)

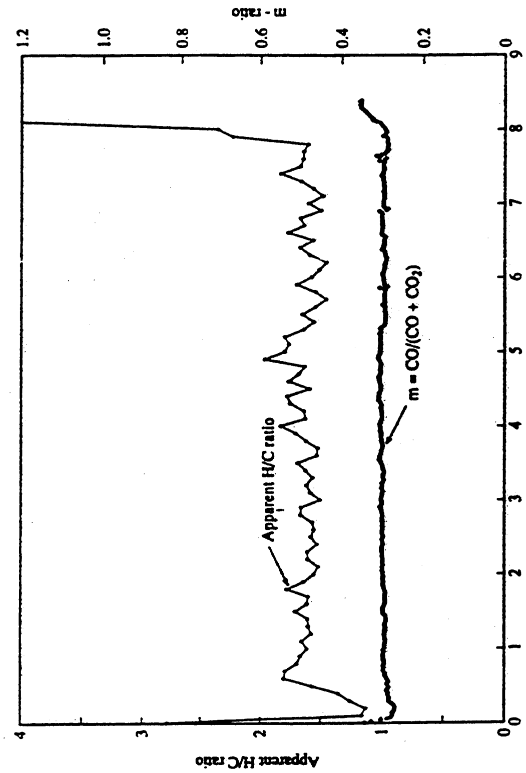


Fig. 4 - Apparent H/C and m-Ratios Versus Time (Run VEN5)

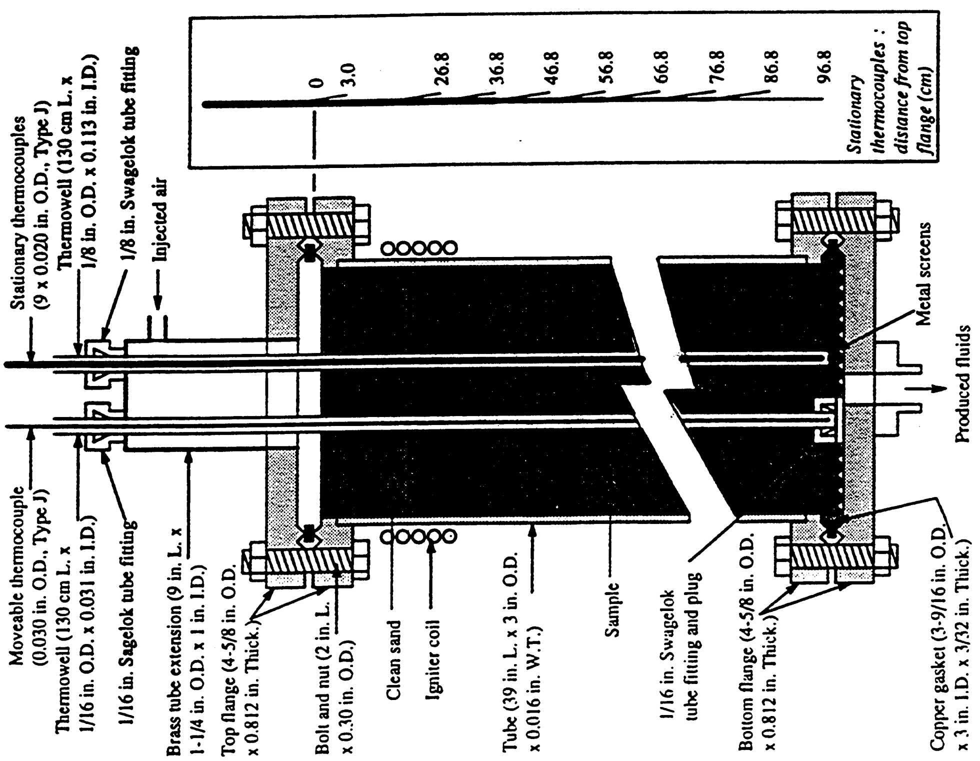


Fig. 2 - Schematic Diagram of Combustion Tube

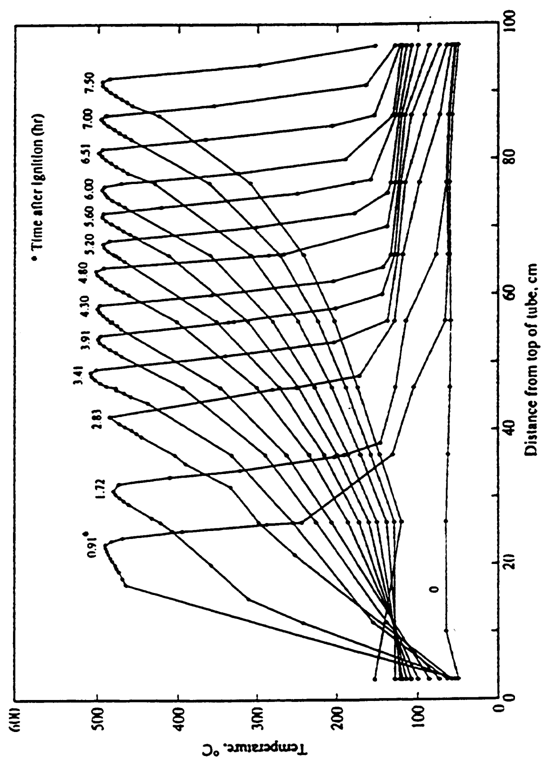


Fig. 5 - Temperature Profiles (Run VEN5)

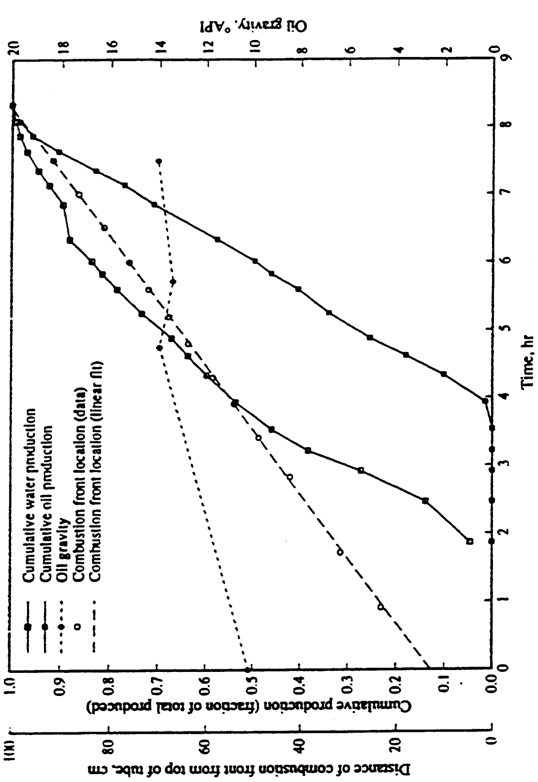


Fig. 6 - Production, Oil Gravity and Combustion Front Location Versus Time (Run VEN5)

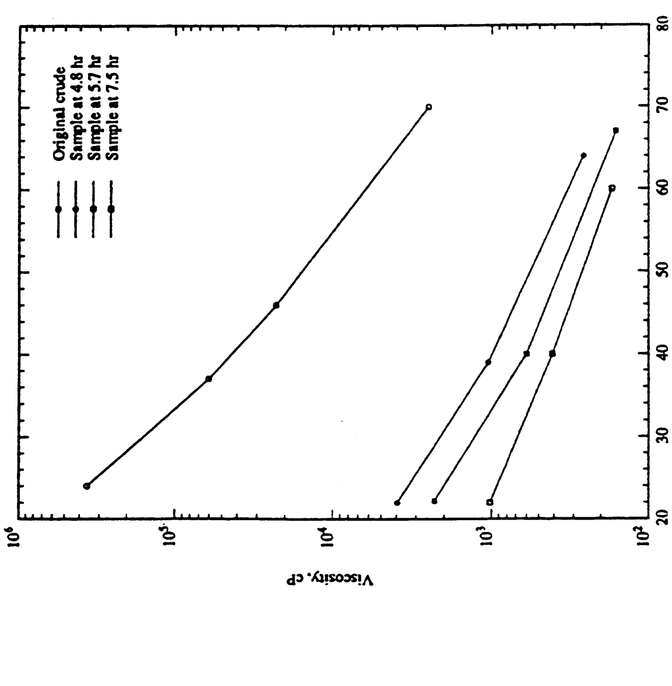


Fig. 7 - Oil Viscosity Versus Temperature (Run VEN5)

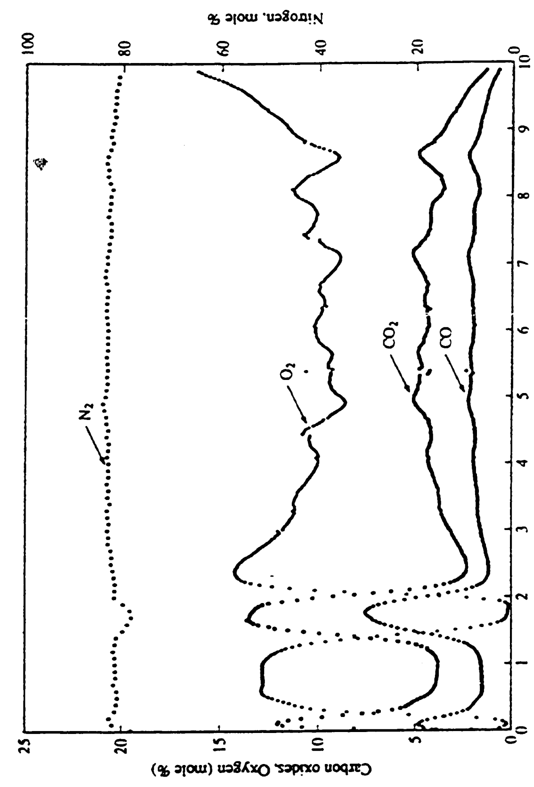


Fig. 8 - Produced Gas Composition Versus Temperature (Run VEN14)

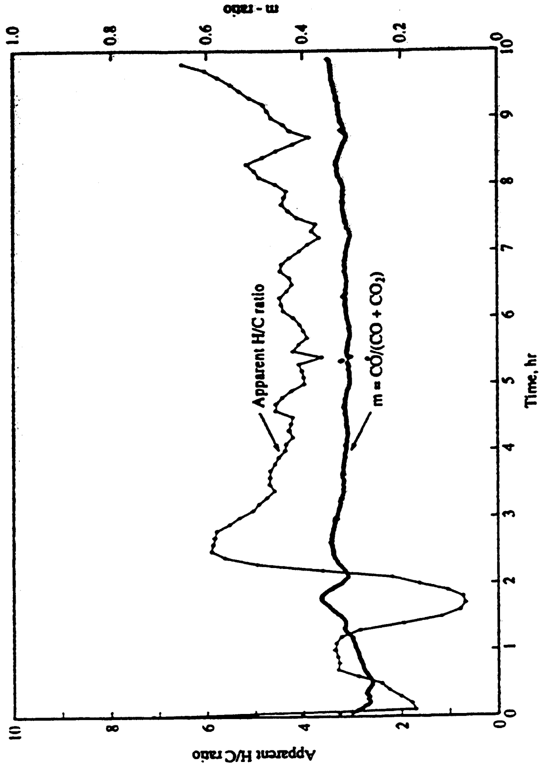


Fig. 9 - Apparent H/C and m-Ratios Versus Time (Run VEN14)

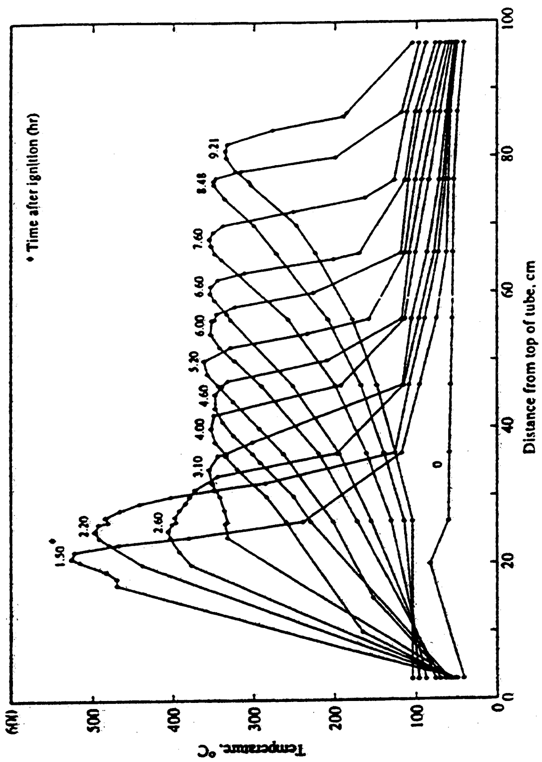


Fig. 10 - Temperature Profiles (Run VEN14)

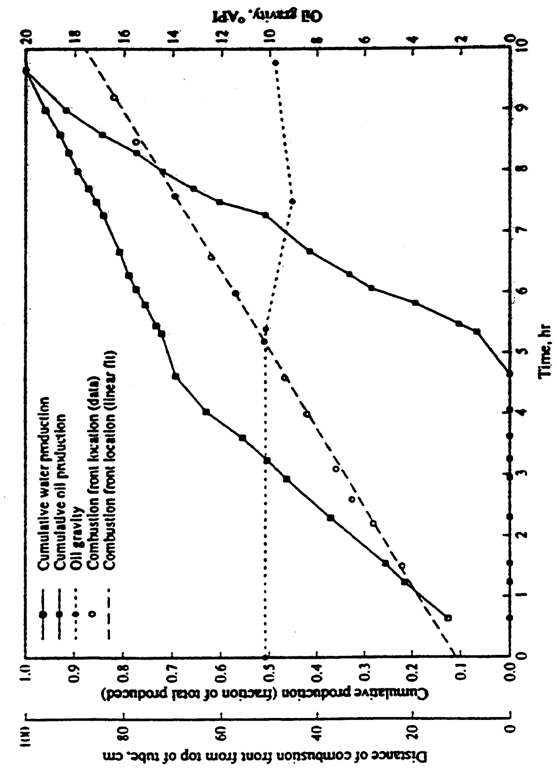


Fig. 11 - Production, Oil Gravity and Combustion Front Location Versus Time (Run VEN14)

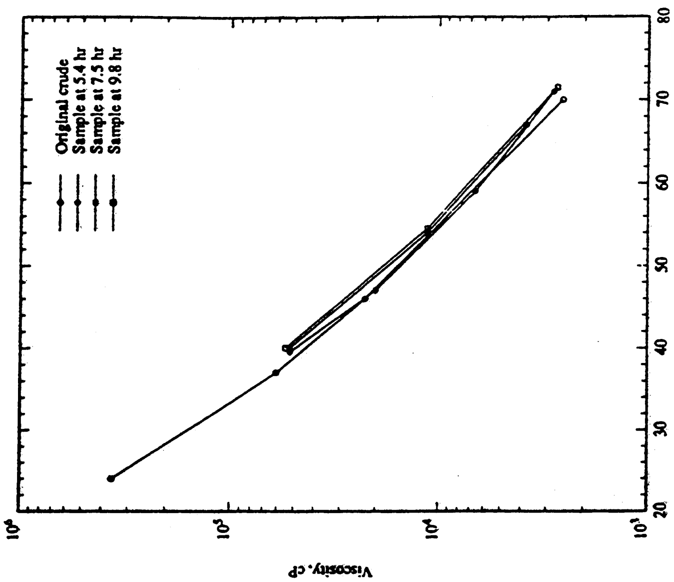


Fig. 12 - Oil Viscosity Versus Temperature (Run VEN14)

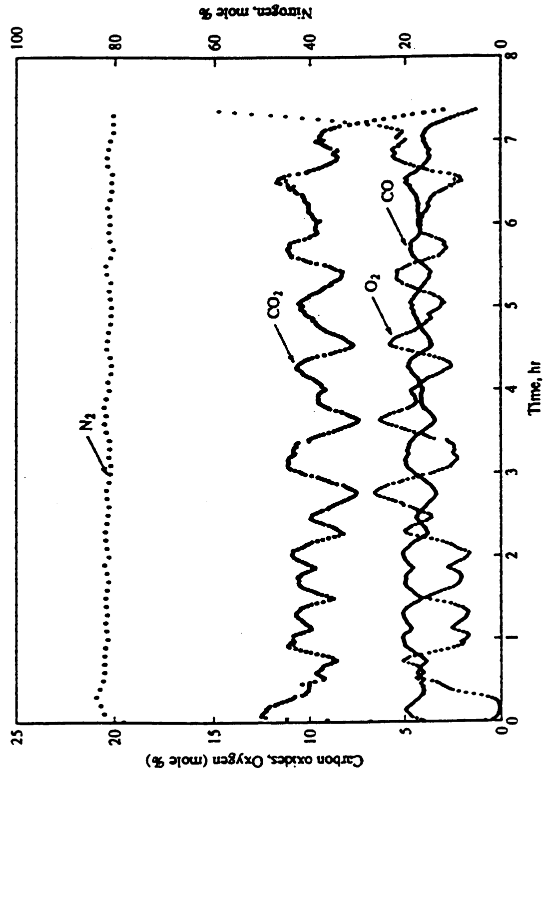


Fig. 13 - Produced Gas Composition Versus Temperature (Run VEN21)

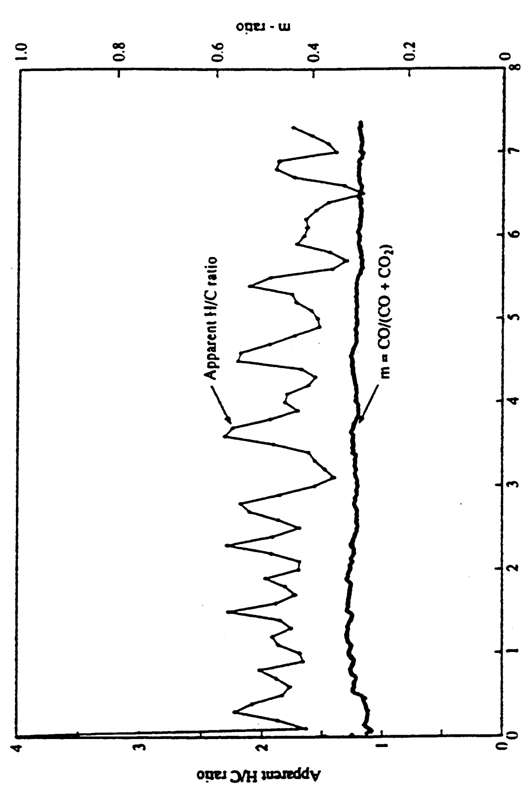


Fig. 14 - Apparent H/C and m-Ratios Versus Time (Run VEN21)

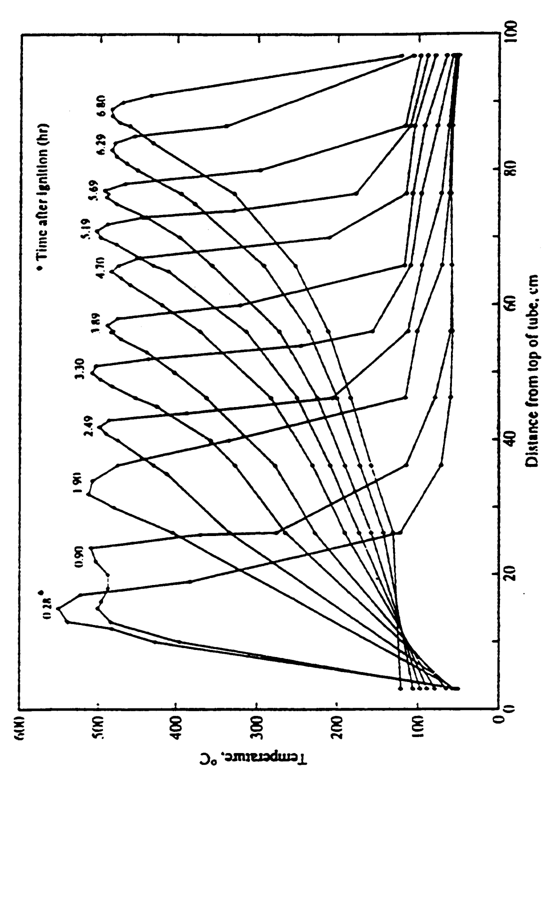


Fig. 15 - Temperature Profiles (Run VEN21)

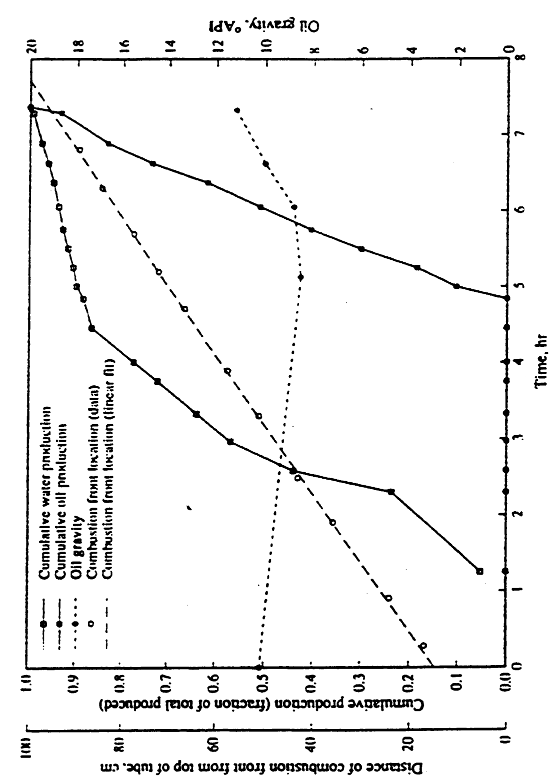


Fig. 16 - Production, Oil Gravity and Combustion Front Location Versus Time (Run VEN21)

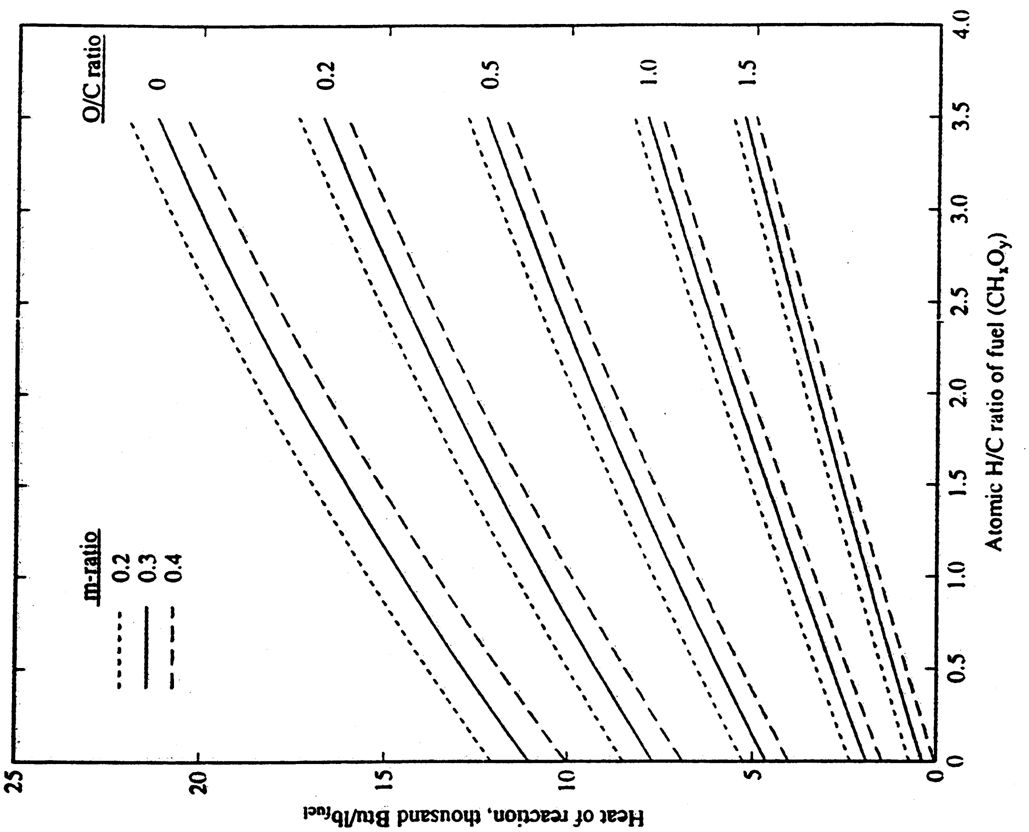


Fig. 19 - Heat of Combustion Versus Atomic H/C, O/C and *m*-Ratios

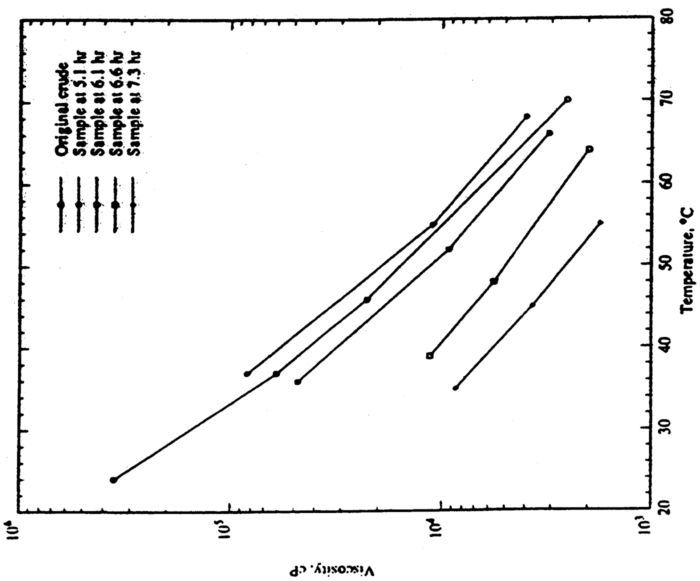


Fig. 17 - Oil Viscosity Versus Temperature (Run VEN21)

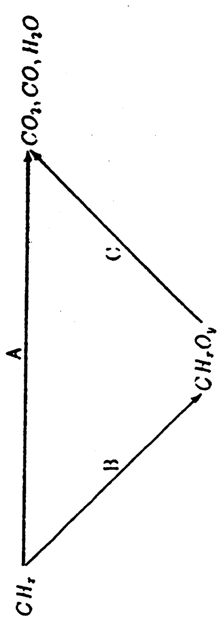


Fig. 18 - Fuel Oxidation Paths

Comprehensive Kinetic Models for the Aquathermolysis of Heavy Oils

by J. D. M. Belgrave, R. G. Moore and M. G. Ursenbach, University of Calgary, Calgary, Alberta, Canada

This paper was originally prepared for presentation at the 45th Annual Technical Meeting of the Petroleum Society of CIM, to be held in Calgary, Alberta, Canada, on June 12-15, 1994. Inclusion herein is with the kind permission of the Petroleum Society of CIM.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

Aquathermolysis experiments over the temperature range 360 to 422° C were performed on core samples taken from three large bitumen and heavy oil deposits found in Alberta: Athabasca, North Bodo, and Frisco Countess. The purpose of this work was to facilitate the development of comprehensive thermal cracking models for predicting gas and liquid phase product distributions under conditions anticipated during thermal recovery. Previous studies have shown by material balance on oxygen that water is implicated in many of the chemical reactions leading to the formation of H_2S and CO_2, yet most of the reported thermal cracking studies have not included water. Additionally, experimental investigations in this area have, for the most part, not involved realistic time frames, and as such certain phenomena observed in this work have not been previously reported.

The experiments conducted using Athabasca bitumen included runs with an initially previously oxidized oil sample (designed to simulate conditions preceding the arrival of the firefront during in situ combustion) and runs with a change in core mineralogy. Pre-oxidizing the oil was found to substantially increase the amount of H_2 generated. Core mineralogy played an important role in the generation CO_2, and the amount of H_2S produced was dependent on oil composition, mineralogy, and time.

Gas production was observed to be largely associated with the conversion of the heavy oil and asphaltenes oil fractions.

The cracking models developed in this work offer useful directional insight as to the effect of core mineralogy and oil composition on the kinetic parameters, and a much needed means of estimating the calorific value and acidic gas content of the produced gases during thermal recovery operations.

References, tables and illustrations at end of paper.

INTRODUCTION

The purpose of this work was to develop thermal cracking models capable of describing the liquid and gas phase compositional changes that occur during thermal recovery operations.

Although rather extensive laboratory studies have been performed concerning the thermal cracking of heavy oils and bitumen, few in comparison have included water as part of the reactants. Laboratory studies[1,2,3] and field applications of thermal recovery processes[4] have demonstrated that appreciable amounts of gaseous environmental contaminants such as H_2S and CO_2 are created by the aquathermolysis (steam/oil reactions) of heavy oils. These problems are all the more severe as the sulphur and oxygen content of the oil increases.[5]

It has also been demonstrated[2] that H_2 and light saturated hydrocarbons are also produced by steam/oil reactions over the over the temperature range 200 to 300° C. Accordingly, casing gas produced from cyclic steam stimulation projects has sometimes been collected and condensed yielding between 0.015 and 1.5 m^3 of condensate per well per day (Anon., 1975), with the noncondensable gas (which contains mostly methane) being used as a supplementary fuel for the steam generators. Thus, aside from the pollution aspect there is the potential to recover chemical energy from the effluent gases.

In this paper we present thermal cracking models based on aquathermolysis experiments performed on core samples from three large bitumen and heavy oil deposits in Alberta: Athabasca, North Bodo, and Frisco Countess. The oils from these deposits have contrastingly different elemental compositions and API gravities. For the experiments involving Athabasca oil sand we report on three sets of tests: two involving significantly different core mineralogy and the third incorporating a pre-oxidized oil sample.

These thermal cracking models offer a much needed means of estimating the calorific value and acidic gas content of produced gases during thermal recovery operations in these fields.

EXPERIMENTAL

The experimental procedures utilized in this work are essentially the same as those described by Hayashitani et al. (1977).

The program involved premixing extracted reservoir sand and oil along with either distilled water or formation brine. Five such samples were prepared. Table 1 shows the composition and properties of the test samples.

Samples 1 and 2 which originated from Athabasca cores differed essentially only in their mineralogical content. Our experience at the University of Calgary has shown that the mineralogical content of the reservoir sand can significantly affect the product distribution from thermal cracking. Sample 3 was made up with Athabasca bitumen that had been oxidized at 150° C with air for 5.5 hours. The intent here was to simulate conditions ahead of the combustion zone in a fireflood process where pre-oxidized oil is exposed to superheated steam (aquathermolysis reactions). The oil elemental analysis and composition of sample 3 (compare with samples 1 and 2) reflects the fact that oxygen was added to the oil.

Samples 4 and 5 were made up with oils of substantially different composition from the Athabasca bitumen; in particular sulphur contents that were much lower than that of the Athabasca bitumen.

The basic test procedure consisted of introducing a 200 g sample of premixed core into a quartz glass tube which was then placed in a stainless steel reaction vessel. The reactor was outfitted with a single bolted closure head through which a nominal 1/32-in., type K thermocouple was inserted and positioned so as to be in contact with the core sample. A pressure transducer and vapour product withdrawal line were included in the head assembly. The reactor was then sealed, evacuated rapidly and charged with helium, and placed in a preheated furnace for the desired test period. For this study, reactions were carried out at 360, 397, and 420° C.

On completion of the test, the reactor was withdrawn from the furnace and lowered into an ice water quench bath. A cooling time of the order of 10 minutes was required to cool the contents to 100°C. Produced gas was removed using a gas syringe, with the volume determined from the syringe readings and the composition determined using a gas chromatograph.

The reactor was then heated to 200° C and the volatiles withdrawn under a vacuum into an ice water trap and a liquid nitrogen trap. The distillate collected in the cold traps was analyzed by a simulated distillation gas chromatograph. That fraction boiling below 300° C was defined as light oil and the 300° C plus fraction defined as heavy oil. The mass of this fraction was added to the heavy oil remaining in the reactor.

Material remaining in the reactor was removed by toluene washing. The sand fraction was dried of solvent and the coke content determined by mass loss on ignition. The toluene soluble material was distilled in a rotary evaporator to remove the toluene, weighed, diluted with pentane and the asphaltenes removed by filtration. The asphaltenes mass was determined by direct weighing following removal of the pentane solvent.

KINETIC MODEL

The kinetic models presented here were constructed around the solid and liquid fractions coke, asphaltenes (ASPH), heavy oil (HO), and light oil (LO), and gas components H_2, CH_4, C_2H_6, CO, CO_2, H_2S, and C_{3+}. The C_{3+} component represents a group of hydrocarbons that ranged from C_3H_8 through C_6H_{14}. Three first order cracking reactions are specified:

$$\begin{aligned} \mathrm{ASPH} \xrightarrow{k_1} & \; a_{11}\mathrm{coke} + a_{12}\mathrm{HO} + a_{13}\mathrm{LO} \\ & + a_{14}H_2 + a_{15}CH_4 + a_{16}CO \\ & + a_{17}CO_2 + a_{18}C_2H_6 + a_{19}C_{3+} \\ & + a_{110}H_2S \end{aligned} \tag{1}$$

$$\begin{aligned} \mathrm{HO} \xrightarrow{k_2} & \; a_{21}\mathrm{coke} + a_{22}\mathrm{LO} + a_{23}CH_4 \\ & + a_{24}C_2H_6 + a_{25}C_{3+} \end{aligned} \tag{2}$$

$$\mathrm{LO} \xrightarrow{k_3} a_{31}\mathrm{coke} + a_{32}CH_4 + a_{33}C_2H_6 + a_{34}C_{3+} \tag{3}$$

where

k_i	=	$A_i \exp(-E_i/RT)$
	=	rate constant (1/h)
A_i	=	pre-exponential factor (1/h)
E_i	=	activation energy (kJ/kmol)
a_{ij}	=	mass fraction of component j among the products of reaction i
R	=	gas constant (8.314 kJ/kmol-K)

The structure of this reaction scheme is based essentially on previous experimental studies and modelling work.

Moschopedis et al.[8] and Savage et al.[9] showed that the products resulting from the pyrolysis of asphaltenes included light nonhydrocarbon gases such as H_2, CO, CO_2, and H_2S. These observations are the rationale for reaction (1).

Reactions (2) and (3) and the general mathematical formulation of the scheme presented here are based on the kinetic modelling work of Behar et al.[10] In their paper, the products of hydrocarbon pyrolysis reactions were specified as being lighter hydrocarbons and coke.

RESULTS

Experimental Observations

Before discussing the kinetic model it is worthwhile to present some important experimental observations.

Figure 1 shows the evolution of H_2 in mg/g initial oil for the five samples at 420° C. Athabasca samples 1 and 2 produced essentially comparable amounts of H_2. The lighter North Bodo and Frisco Countess oils (core samples 4 and 5) also behaved similarly in H_2 formation but tended to produce more H_2 than the Athabasca samples 1 and 2.

On the other hand, Athabasca sample 3, which had been pre-oxidized, produced significantly higher quantities of H_2 than either of the Athabasca samples as wells as the North Bodo and Frisco Countess cores. This indicates that low temperature oxidation of oil prior to the arrival of the high temperature front may be an important mechanism regarding molecular hydrogen generation production in fireflood projects. This phenomenon has not been previously reported and should be investigated further.

Figure 2 is typical of the CO_2 production profiles for all samples at the three temperatures. Low temperature oxidation had little effect on the generation of this component (compare results for samples 1 and 3), whereas the change in core mineralogy associated with Athabasca sample 2 appears to have been responsible for the substantial suppression of CO_2 formation.

Figure 3 compares H_2S formation from the test samples at 397° C. It shows that around 6 to 8 hours there was a net reduction in the amount of H_2S produced, indicating a sequential reaction that consumes this component. This result has important implications for thermal recovery projects in that longer gas residence times in the reservoir could be accompanied by a reduction in the acid gas content of the effluent stream. It also emphasizes the need to conduct these experiments using laboratory time frames that are compatible with reservoir fluid residence times.

Our experimental program did not allow detection of sulphur dioxide which is known to be produced during the thermal decomposition of heavy crudes,[11] neither did it include a post experimental analysis for elemental sulphur deposited on the core. It was however possible to measure COS concentrations in the produced gas, but this data did not produce any acceptable correlation with the formation/removal of H_2S. Thus we were unable to suggest a definitive reaction pathway for H_2S removal.

Figure 4 is considered to be representative of the liquid compositional changes that occurred during the experiments. The asphaltenes and heavy oil fractions essentially converted to form coke and gas and to increase the light oil content.

Kinetic Model Parameters

The kinetic parameters and stoichiometric coefficients were estimated by least squares minimization of the sum of the squared residuals, using a hybrid of the Gauss-Newton and steepest descent techniques. Table 2 lists the results.

For sample 2 the pre-exponential factor associated with reaction (3) was zero, suggesting that the thermal cracking of light oil (as formulated) did not occur to any appreciable extent. Table 2 also shows that for all the samples there was no direct conversion of asphaltenes to light oil ($a_{13} = 0$).

Figures 5 through 9 show the computed concentrations (mass fraction) versus the experimental data for samples 1 to 5, respectively.

For all samples, the concentration predictions for coke, asphaltenes, heavy oil, and light oil is satisfactorily represented by the model. It is interesting to note that hydrogen generation is also adequately correlated with the conversion of asphaltenes, for all samples.

The comparisons for the hydrocarbon gases CH_4, C_2H_6, and C_{3+} exhibit some scatter, but the model does follow the trend of the experimental data. The most favourable comparisons for these gases is observed with Athabasca sample 1, while those with the most scatter are for the pre-oxidized Athabasca sample 3. The latter observation is not surprising since the chemical nature of oil is substantially altered by low temperature oxidation reactions.

The only appreciable and consistent lack of predictive capability of the model occurred with the carbon oxides. Carbon monoxide is observed to be generally uncorrelatable with the asphaltenes decomposition. Indeed, we found the formation of this gas to also be uncorrelatable with the conversion of heavy oil.

The trends in Figures 5 to 9 for CO_2 show a consistent linear clustering of the comparison points that occurs at an angle oblique to that describing a good fit of the data. This suggest that the prediction of CO_2 generation might be improved by an independent parallel asphaltenes decomposition reaction.

With respect to the formation of H_2S, Athabasca samples 1 and 2 were well described by the model owing to the fact that the experiments on these samples were not conducted for durations beyond around 8 hours. Thus there was no reduction in H_2S at extended reaction times to influence the regression.

In general, this three reaction kinetic model captured many of the experimentally observed trends, and could be easily implemented in reservoir simulation studies on thermal recovery processes for these fields. The experimental results and parameter estimation work suggests that this model could be improved by an additional reaction that accounts for the disappearance of H_2S and an independent reaction for CO_2 generation.

CONCLUSIONS

1. A kinetic model has been developed that describes many of the experimentally observed trends in compositional changes that occur during the thermal cracking of Athabasca, North Bodo and Frisco Countess Oils.
2. Low temperature oxidation of the oil phase increases the quantity of molecular hydrogen generated by thermal cracking reactions, and hydrogen generation was observed to correlate well with the decomposition of asphaltenes.
3. Core mineralogy was found to play an important role in the amount of CO_2 produced and to significantly impact the reaction model kinetic parameters.
4. The amount of H_2S produced by thermal cracking reactions was observed to time dependent, with a net reduction in its concentration occurring beyond 6 to 8 hours.
5. Carbon monoxide formation was found to be uncorrelatable with any of the experimentally observed liquid compositional changes.

ACKNOWLEDGMENTS

The authors gratefully acknowledge the significant financial support of the Alberta Oil Sands Technology Research Authority (AOSTRA) and the Natural Sciences and Engineering Research Council of Canada (NSERC). We also thank the technical staff of the University of Calgary for their many valuable contributions.

REFERENCES

1. Actant, M.H.: "Gas Evolution and Change of Oil Composition During Steam Flooding of Oil Reservoirs," *J. Pet. Geol.*, v. **5**, 1983, pp. 363-388.
2. Hyne, J.B., J.W. Greidanus, J.D. Tyrer, D. Verona, C. Rizek, P.D. Clark, R.A. Clarke and J.F.K. Koo: "*Aquathermolysis of Heavy Oils*," in "*Second Internation. Conf., The Future of Heavy Crude and Tar Sands*," McGraw Hill, New York, 1984, pp. 404-411.
3. Monin, J.C., and A. Audibert: "Alteration of Heavy Crudes Under High Pressure Steam Conditions," Preprints, Div. Petrol. Chem., ACS, v. **29**, 1984, pp. 1223-1231.
4. van Dijk, C.: "Steam-drive Project in the Schoonebeek Field, The Netherlands," in "Thermal Recovery Techniques," SPE Reprint Series No. 10, 1972, pp. 111-118.
5. Burger, J., P. Sourieau and M. Combarnous: "*Thermal Methods of Oil Recovery*," Gulf Publishing Co., Houston, 1985, p. 81, 84.
6. Anon.: "Continuous Steam Injection, Heat Scavenging Spark Kern River," *Oil Gas J.*, v. **73**, 1975, pp. 127-141.
7. Hayashitani, M., D.W. Bennion, J.K. Donnelly, and R.G. Moore: "*Thermal Cracking Models for Athabasca Oil Sands Oil," in "The Oil Sands of Canada-Venezuela (1977)*," D.D. Redford and A.G. Winestock, Eds., CIM Special, v. **17**, 1977, pp. 233-247.
8. Moschopedis, S.P., S. Parkash, and J.G. Speight: "Thermal Decomposition of Asphaltenes," *Fuels*, v. **57**, 1978, pp. 431-434.
9. Savage, P.E., M.T. Klein, and S.G. Kukes: "Asphaltene Reaction Pathways. 1. Thermolysis," *Ind. Eng. Chem. Process Des. Dev.*, v. **24**, 1985, pp. 1169-1174.
10. Behar, F., P. Ungerer, A. Audibert, and M. Villalba: "Experimental Study and Kinetic Modelling of Curde Oil Pyrolysis in Relation to the Thermal Recovery Processes," Paper No. 97, Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands, Edmonton, Alberta, Aug. 7-12, 1988.
11. Speight, J.G.: "High Temperature Mass Spectroscopy of Athabasca Asphaltenes and the Relationship to Cracking Processes," Preprints, Div. Petrol. Chem., ACS, v. **15**, 1971, pp. 57-61.

TABLE 1
Experimental initial rock and fluid properties.

	Athabasca Sample #1	Athabasca Sample #2	Athabasca Sample #3	North Bodo Sample #4	Frisco Countess Sample #5
Oil elemental analysis (mass %)					
C	84.20	84.00	82.68	85.40	80.34
H	10.20	10.10	9.65	10.50	10.82
N	0.30	0.40	0.51	0.40	0.14
S	4.40	4.40	4.64	2.85	1.91
Oil composition (mass %)					
asphaltenes	18.9	20.7	31.3	9.3	8.1
heavy oil	75.9	74.2	64.3	84.9	86.0
light oil	5.2	5.1	4.4	5.8	5.9
Oil density (kg/m^3)	1004.5	1005.6	1009.5	975.8	902.0
Oil pre-oxidized	No	No	Yes	No	No
Sand properties					
surface area (m^2/g)	0.43	0.43	0.43	1.5	0.9
quartz (mass %)	89	78	94	69	95
feldspar (mass %)	1	17	3	24	1
kaolinite (mass %)	6	3	2	6	3
illite (mass %)	2	trace	trace	1	trace
Type of water	distilled	distilled	distilled	formation brine	formation brine

TABLE 2
Kinetic Model Parameters and Stoichiometric Coefficients

	Sample #1	Sample #2	Sample #3	Sample #4	Sample #5
A_1	3.509266E+15	1.149885E+15	1.456671E+7	2.052380E+23	1.202942E+06
E_1	209454	181041	102790	327499	97881
A_2	1.986868E+13	7.162405e+08	1.926755E+08	3.241917E+08	7.463604E+11
E_2	184938	129935	119371	122226	165739
A_3	42.5	0.0	10.1	0.19	0.05
E_3	33380	-	34408	15973	8526
a_{11}	0.1090	0.1729	0.4719	0.0000	0.0000
a_{12}	0.1769	0.3016	0.2438	0.3149	0.0959
a_{13}	0.0000	0.0000	0.0000	0.0000	0.0000
a_{14}	0.0024	0.0028	0.0062	0.0304	0.0348
a_{15}	0.0000	0.1462	0.0000	0.0000	0.0000
a_{16}	0.0014	0.0007	0.0066	0.0125	0.0010
a_{17}	0.6443	0.0928	0.2121	0.3121	0.7158
a_{18}	0.0000	0.0912	0.0000	0.0000	0.0000
a_{19}	0.0000	0.0293	0.0000	0.0000	0.0000
$a_{1\ 10}$	0.0660	0.1625	0.0600	0.3301	0.1525
a_{21}	0.1016	0.3060	0.3786	0.1697	0.0500
a_{22}	0.8984	0.6940	0.6214	0.7825	0.9151
a_{23}	0.0000	0.0000	0.0000	0.0286	0.0120
a_{24}	0.0000	0.0000	0.0000	0.0120	0.0187
a_{25}	0.0000	0.0000	0.0000	0.0072	0.0042
a_{31}	0.7322	0.0000	0.3927	0.7480	0.8447
a_{32}	0.1301	0.0000	0.3037	0.1172	0.0560
a_{33}	0.1177	0.0000	0.2794	0.1274	0.0945
a_{34}	0.0200	0.0000	0.0242	0.0074	0.0048

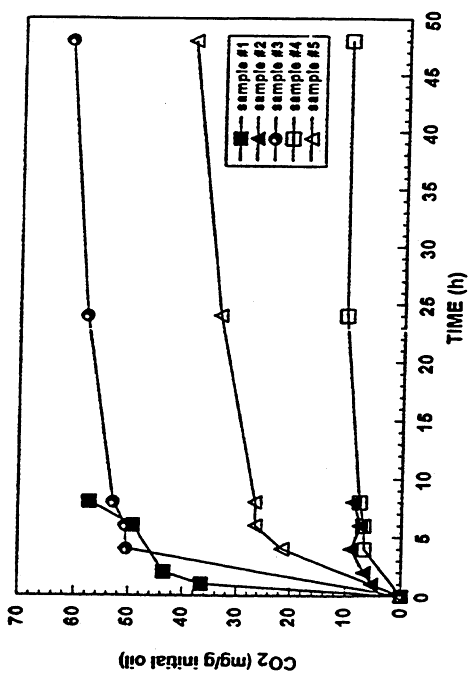


FIGURE 2: Experimental Carbon Dioxide Generation at 420°C.

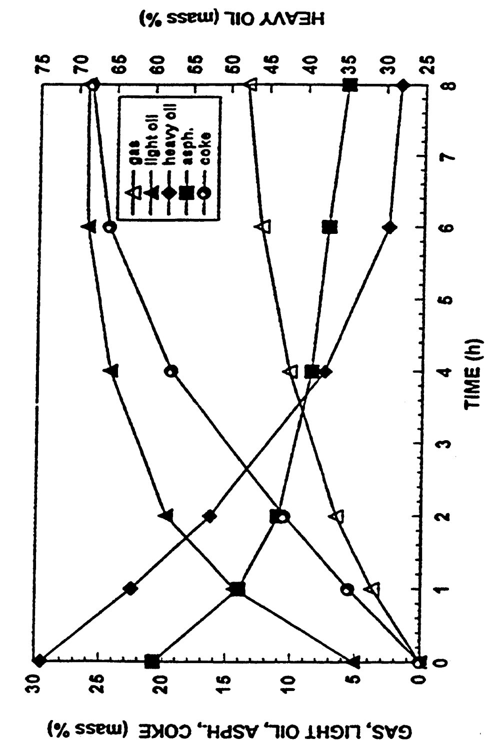


FIGURE 4: Experimental Liquid Compositional Analysis for Athabasca Sample #2 at 420°C.

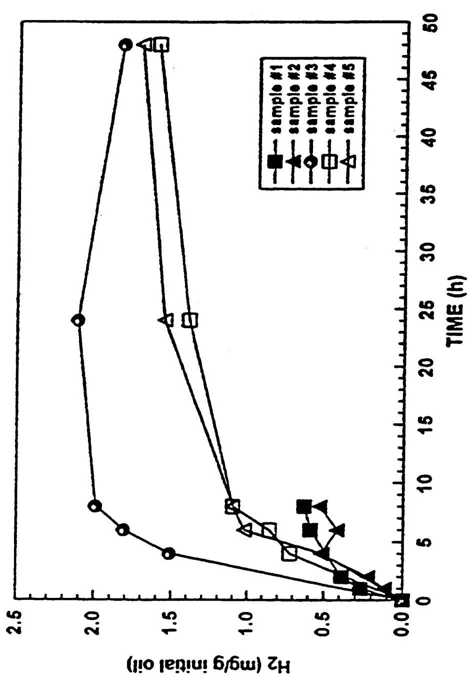


FIGURE 1: Experimental Hydrogen Generation at 420°C.

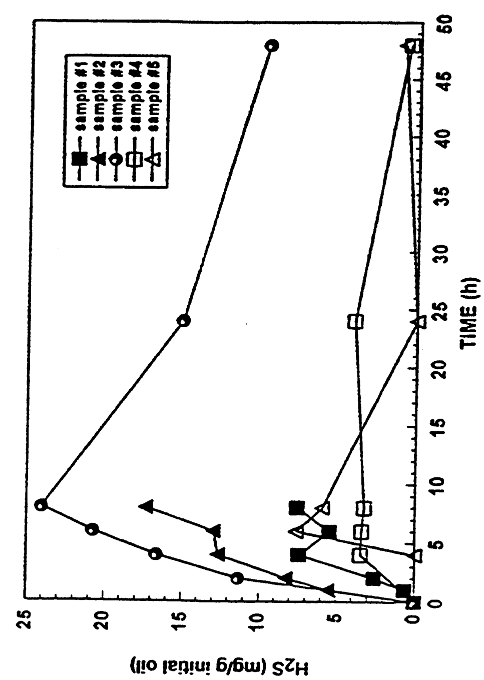


FIGURE 3: Experimental Hydrogen Sulphide Generation at 397°C.

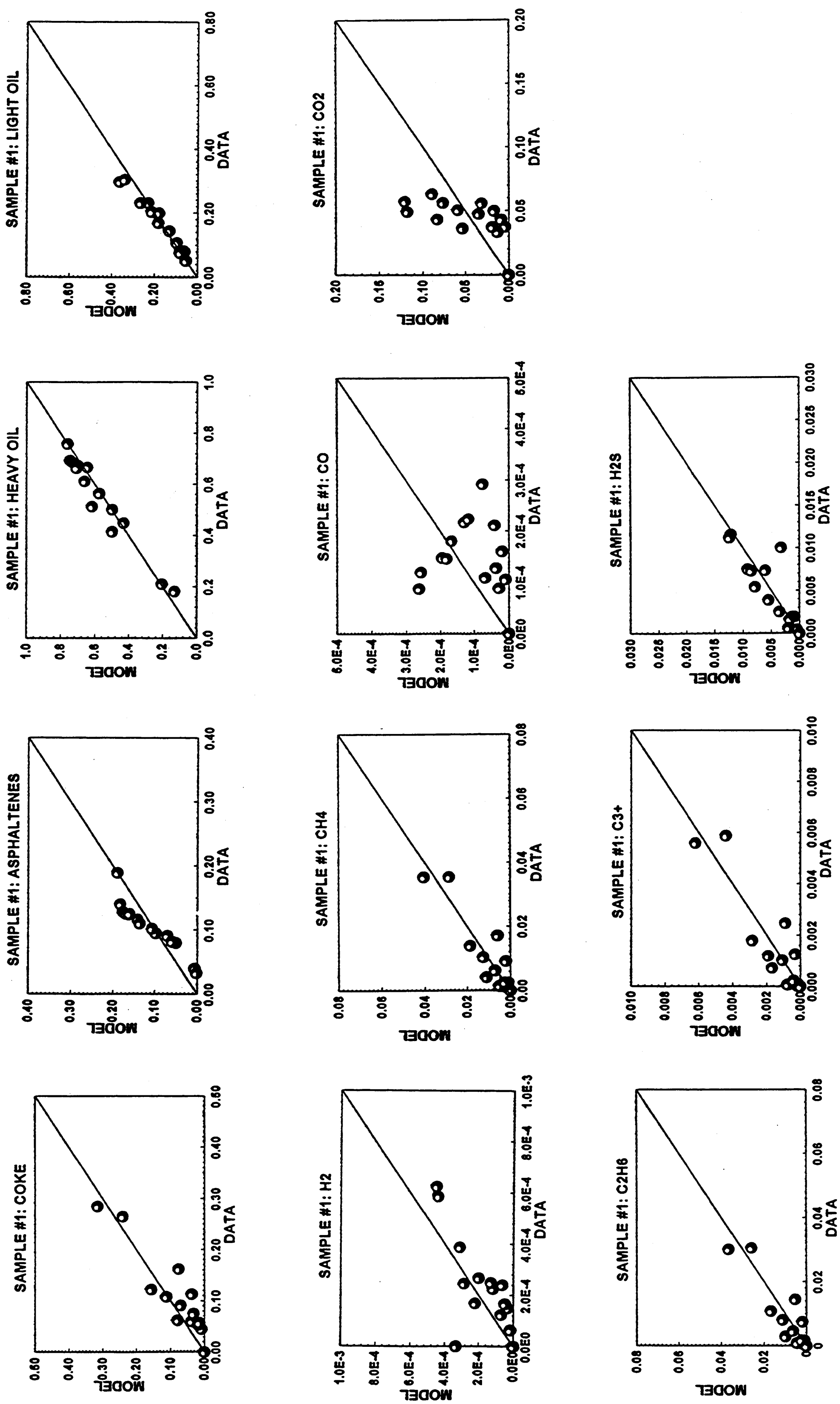


FIGURE 5: Computed Concentrations (mass fraction) from the Kinetic Model versus Observed Concentrations for Athabasca Sample #1.

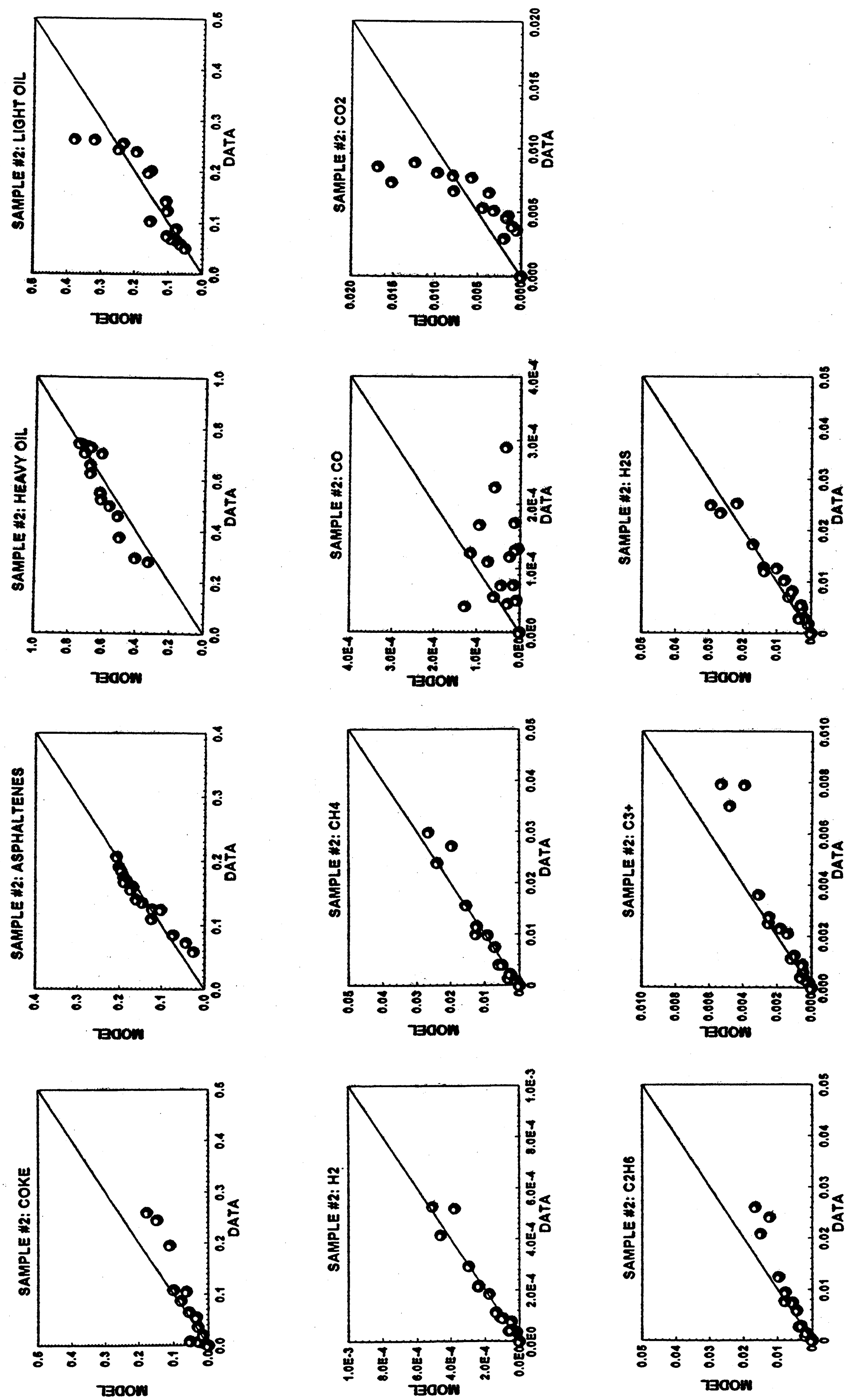


FIGURE 6: Computed Concentrations (mass fraction) from the Kinetic Model versus Observed Concentrations for Athabasca Sample #2.

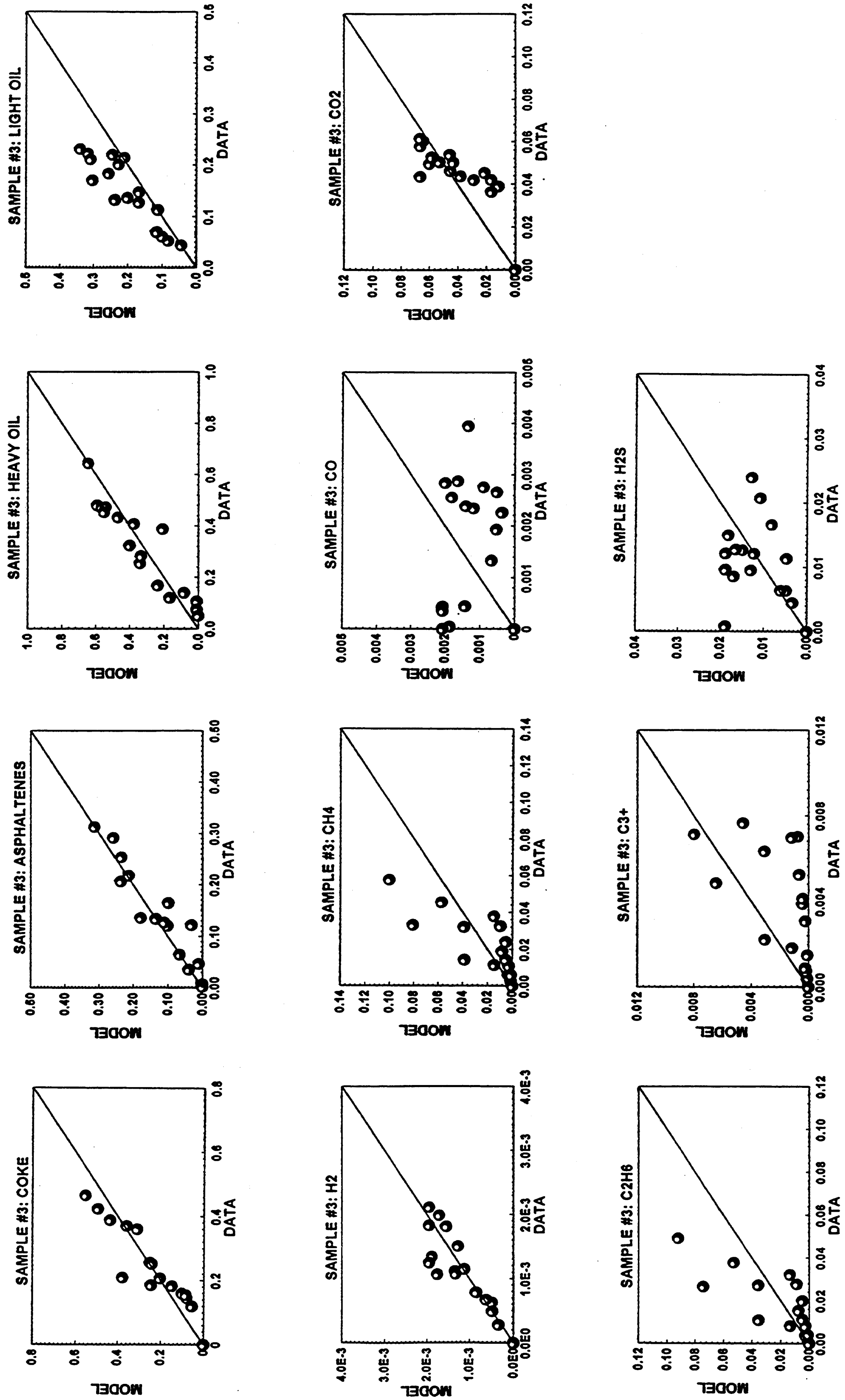


FIGURE 7: Computed Concentrations (mass fraction) from the Kinetic Model versus Observed Concentrations for Athabasca Sample #3.

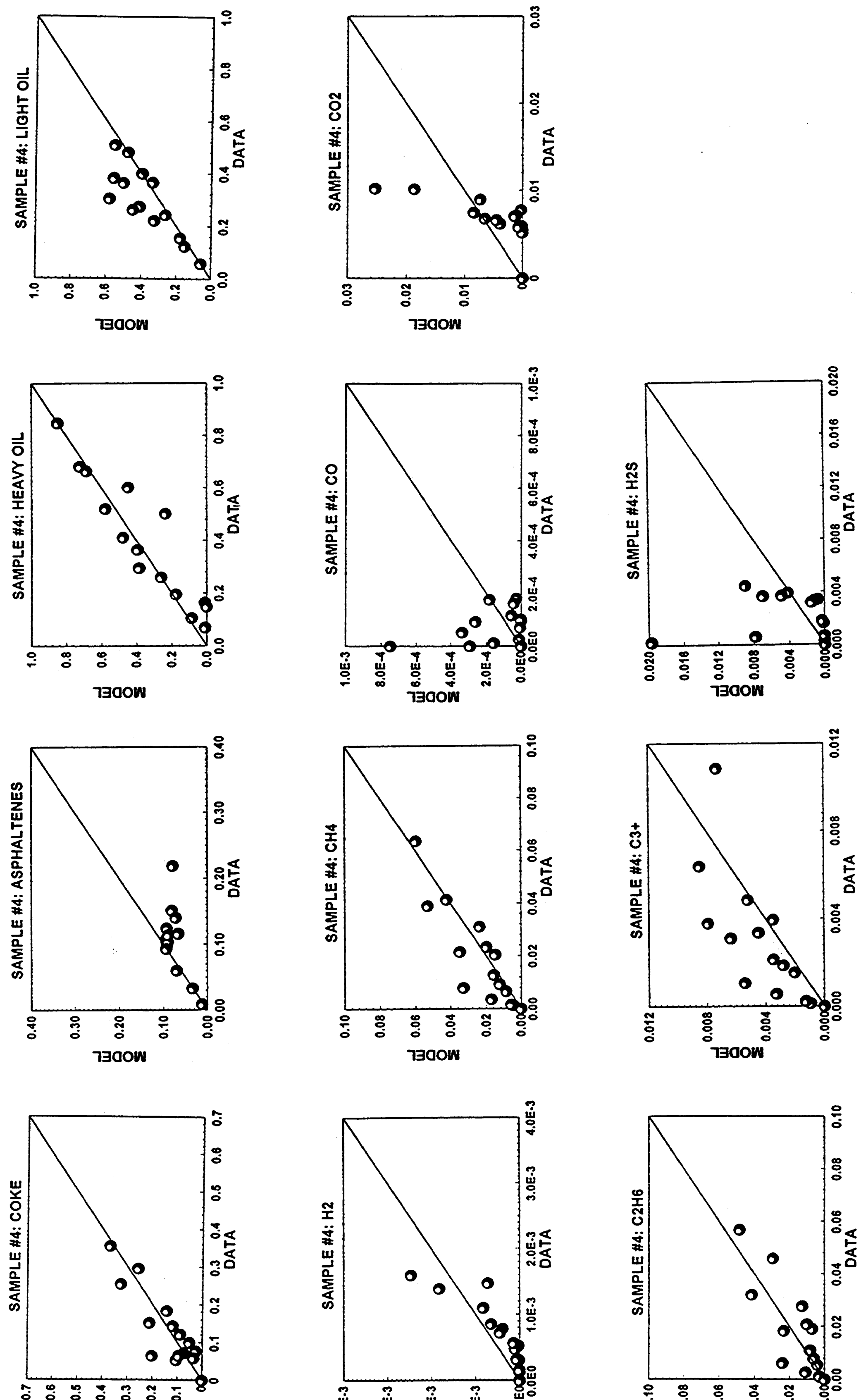


FIGURE 8: Computed Concentrations (mass fraction) from the Kinetic Model versus Observed Concentrations for North Bodo Sample #4.

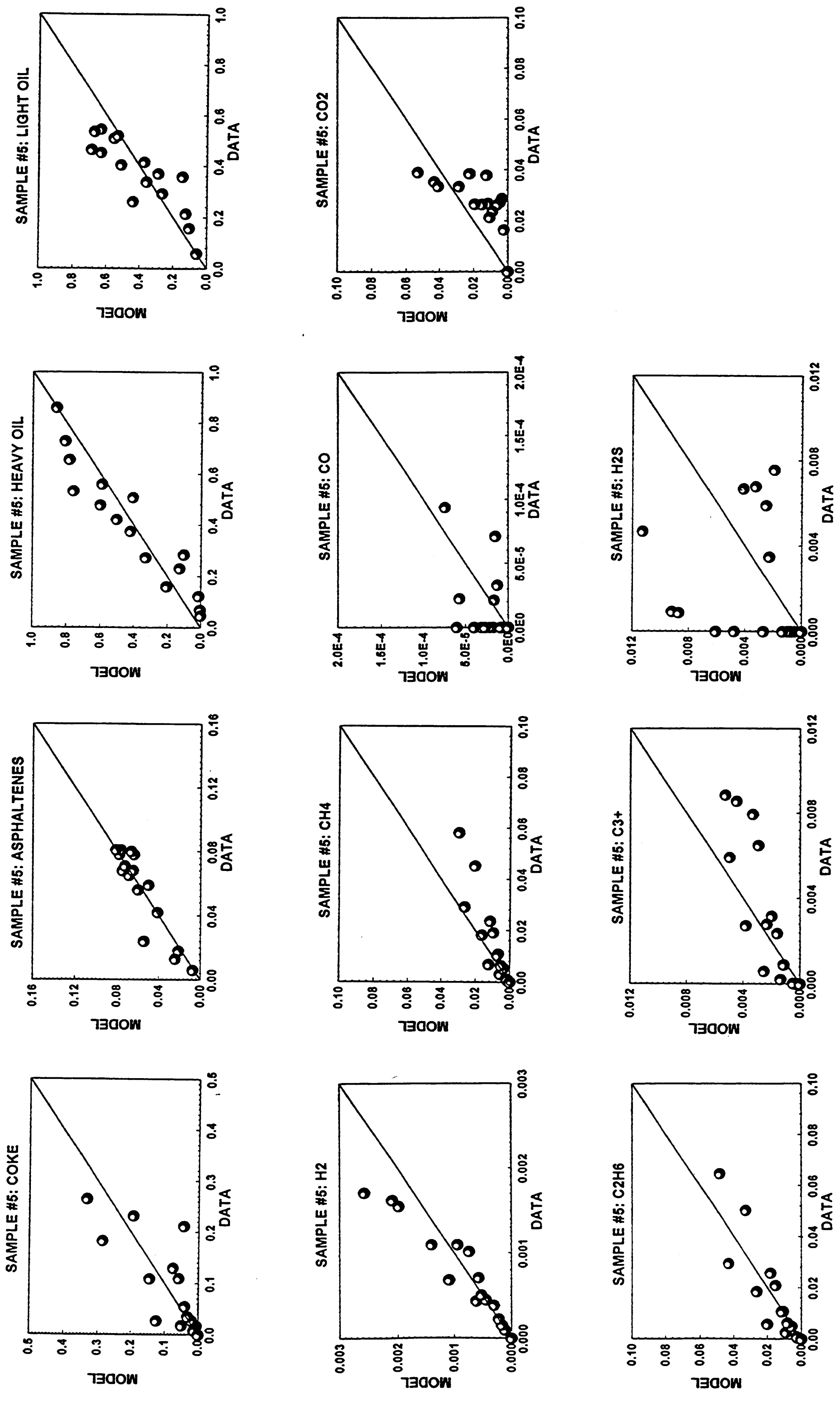


FIGURE 9: Computed Concentrations (mass fraction) from the Kinetic Model versus Observed Concentrations for Frisco Countess Sample #5.

LABORATORY STUDIES
DISCUSSION

Session Chairman: D. Yannianaras, Amoco Production Research

Speakers: D. D. Mamora, Texas A&M University, College Station, TX
J. D. M. Belgrave, University of Calgary, Alberta, Canada

Paper ISC-7—The Effect of Low Temperature Oxidation on the Fuel and Produced Oil During In Situ Combustion

Question for Mamora from D. Yannimaras, Amoco Production Research

In your first HTO Run (Run Ven 5), you have indicated that based on produced gas analysis, your calculated H/C ratio (1.63) was almost identical to the original crude (1.65). My experience is the estimated H/C ratio is usually lower. Can you comment on it?

Response by Mamora, Texas A&M University, College Station, Texas

I agree with you, but it is not unusual for the two values to be nearly the same. It merely indicates that the combustion is complete. There are a number of cases reported in the literature where the calculated and original H/C ratio are almost the same.

Question for Mamora from Norman Freitag, Saskatchewan Research Council, Regina, Canada

In your sand-clay run, what kind of clay did you add to the sand? Did you perform any runs to check whether different clays give different results?

Response by Mamora, Texas A&M University, College Station, Texas

We added 6% by weight of clay, which is mostly kaolinite, to the sand. We did not investigate the effect of different clays on combustion performance.

Question for Mamora from Norman Freitag, Saskatchewan Research Council, Regina, Canada

A 20-30 mesh sand with no clay will result in a highly porous pack, and one is likely to drive out most of the oil and very little to burn. How did you decide that you are getting a LTO?

Response by Mamora, Texas A&M University, College Station, Texas

Even though the pack is porous, we did not drain most of the oil. Analysis of produced gas indicated a very high H/C ratio, which is an indication of LTO. We also found an increase in the viscosity and a decrease in the API gravity of produced oil.

Paper ISC-8—Comprehensive Kinetic Models for the Aquathermolysis of Heavy Oils

Question for John Belgrave from an Unknown Person

You have indicated that your H_2S production peaked and then declined over a time, while your hydrogen did not. Can you comment please?

Response from Belgrave, University of Calgary, Canada

We suspect that the decline H_2S peak may be due to the decomposition of H_2S into sulfur and hydrogen. There is some experimental basis for that; however, at this point we have no concrete evidence to verify this hypothesis.

Question for John Belgrave from Jeff Weissman, Texaco, Inc., Glenham, New York

You assumed that the heavy oil and light oil produced by asphaltene decomposition contained no sulfur. It that correct?

Response from Belgrave, University of Calgary, Canada

That is right.

Comment by Jeff Weissman, Texaco, Inc., Glenham, New York

We find in our downstream operation, reactions similar to what you have described. I suggest that you consider analyzing your heavy and light oils for sulfur, because in refinery operations sulfur content of gas-oils and naphtha that you produce by decomposing the asphalt is a severe problem.

An Evaluation of the Benefits of Combined Steam and Fireflooding as a Recovery Process for Heavy Oils

by R. G. Moore, C. J. Laureshen, J. D. M. Belgrave, M. G. Ursenbach, S. A. Mehta, University of Calgary, Alberta, Canada, and K. N. Jha, Department of Natural Resources Canada, Ottawa, Canada

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

Lack of oil mobility is a major problem with in situ combustion field projects, since the combustion front displaces oil into an essentially unheated reservoir. One way of ensuring oil mobility is to utilize steam injection during the early life of the process, and then switch to combustion when heated communication paths have been developed.

The in situ combustion characteristics of cores from the Primrose reservoir of Northeastern Alberta were investigated in a comprehensive series of 22 combustion tube tests. The program was carried out in order to evaluate the effectiveness of fireflooding in both cores that had been preheated to the extent that the oil was mobile and in those which were steam-flooded prior to dry combustion. Both normal- and 95% oxygen-enriched air were evaluated. Wet combustion tests were performed utilizing both liquid water and steam injection. The effects of parameters such as pressure, oxygen enrichment and injection flux on the combustion characteristics were examined.

This paper will discuss the results of this study, which show that steam co-injection is more effective at lowering the oxygen requirement than was combustion following steam. Additionally, the cores which were preheated exhibited similar oxygen requirements to those which were presteamed to a near-residual saturation.

References, tables and illustrations at end of paper.

INTRODUCTION

In situ combustion, or fireflooding, is an oil recovery process in which an oxygen-containing gas is injected into a reservoir so as to displace oil ahead of a propagating combustion zone. Although fireflooding is normally classified as a thermal process, in fact, it is much more a displacement process, as the mobilized oil is pushed into the unheated portion of the reservoir. At the relatively-low temperatures and high viscosities associated with most Canadian heavy oil and bitumen reservoirs, this leads to restricted gas flow and plugging and, almost invariably, results in the failure of any attempt to employ in situ combustion. Steam preheating of the reservoir appears to be the most economic method for generating sufficient oil mobility to allow combustion to achieve efficient operation.

In order to examine the benefits of the combination of steam and fireflooding, a parametric study on steam-assisted in situ combustion was undertaken. The objectives of this study were to define the characteristics of Primrose oil at operating pressures of 4.1 and 10.3 MPa using both normal air and oxygen, and to evaluate dry combustion as a follow-up to a steamflood. In addition, tests were also performed to evaluate the co-injection of superheated steam and oxygen, as this type of process has the potential to propagate a high-quality steamflood for large distances away from an injection well. The core material and produced oil and brine for the runs were provided by Amoco Canada Petroleum Company from their Primrose reservoir in Northeastern Alberta. This field, which is located in the Clearwater formation (a member of the Lower Cretaceous Manville group), is typical of Alberta's Cold Lake region, and has oil gravities in the range of 9 to 12° API.

IN SITU COMBUSTION TUBE TEST PROGRAM

Twenty-two (22) in situ combustion tube tests were performed during the course of this investigation. Thirteen of these tests were operated as "traditional" combustion tube tests; that is, communication through the core was established with helium, followed by combustion using air/enriched-air injection, then purging with helium. Of these 13 tests, five used normal air and the balance used enriched (95% oxygen, 5% nitrogen) air. Seven of the 13 tests were dry, while the other six involved the co-injection of Primrose field brine.

Of the remaining nine tests, five were first waterflooded at 90° C followed by steamflooding. Both floods were carried out to near-residual saturations. Following the steamflood, dry combustion was initiated using oxygen-enriched air. The remaining four tests involved the co-injection of steam and enriched air during the combustion sweep.

Twenty of the 22 tests were performed in the 1.1 m long by 5 cm I.D. combustion tube, while two calibrating tests were carried out in the 1.83 m long by 10 cm I.D. system.

This wide range of operating procedures required an extremely flexible and well-equipped reactor system. The following sections describe the combustion tube test facility at the University of Calgary, and detail the test operation as well as the pre- and post-test procedures.

Equipment

Combustion Tube System

The small combustion tube system on which 20 of the 22 tests were performed was essentially the apparatus which was constructed and reported by Sibbald *et al.*[1] Figure 1 is a block diagram showing the major components of the experimental facility.

The combustion tube located inside the vessel was oriented vertically, with the injection end at the top. The reason for the pressure vessel was to allow the use of a thin-walled combustion tube and high, realistic process pressures. A thin combustion tube wall was required to minimize heat transfer along the wall so as to help control system-induced effects on the simulated steamflood and combustion processes. In the case of the original large tube, which was used for Tests 18 and 19, these internal pressures had to be approximately balanced by external pressures which were imposed by injecting helium into the annular region between the combustion tube and the pressure vessel wall. The smaller tube allowed the use of high net external pressures, which promoted pack/internal tube wall contact and made experimental operation simpler. This was also achieved by pressurizing the annular region between the combustion tube and the pressure jacket with helium to the desired level. The small tube system was also equipped with a steam generator located immediately upstream of the injection face of the core.

Combustion Tube

A schematic diagram of the small combustion tube used for 20 of the 22 tests is shown in Figure 2. The basic design concept was that of a thin-walled tube, employing insulation around the tube with heaters placed on this layer. The tube itself was constructed of nominal two-inch (5 cm) Type 321 stainless steel tubing, with a length of approximately 42 inches (1.07 m) and a 0.035 inch (1 mm) wall thickness. The tube system used 14 heating zones of 3 inch (7.62 cm) length with the centerline and wall thermocouples placed at the center of each zone. Centerline thermocouples were inserted radially through Swagelok fittings, while wall thermocouples were welded to the outside tube wall. Six pressure taps were located at 6 inch (15.24 cm) intervals along the tube.

The purpose of the thermocouple pairs, as well as recording the velocity and temperature of the passing fronts, was to provide an active insulation to the tube. As the centerline thermocouple detected the approach of a higher-temperature front, the heater was activated in order to bring the wall temperature within a set temperature differential of the center (usually 1° C less than the center temperature). Sibbald *et al.* provide a useful discussion of insulation and heater control strategies.[1]

The large-diameter tube on which two tests of the program were performed was nominal 4 inches (10 cm) in diameter with a wall thickness of 0.040 inch (1 mm) and a length of 6 feet (1.835 m). It was constructed of Type 600 Inconel. It had 12 six-inch heating zones, and six pressure taps located at 12 inch intervals. The large tube was not designed to operate with an overburden stress or a steam generator.

Steam Generator

The small-diameter combustion tube was equipped with a specially-designed steam generator, capable of delivering superheated steam to the core face. The steam generator essentially consisted of a 137.8 inch (3.5 m) length of 1/8 inch (3.2 mm) stainless steel tubing spirally wound around the outside of a cylindrical (5 cm diameter), grooved, solid stainless steel end cap. Water entered the coil at the downstream end of the cap, and then flowed to the upstream end prior to being directed into a centrally-drilled port. Nominal 1000 W clamshell-type heaters were clamped around the outside of the system to vaporize the water, with the end cap providing thermal ballast to ensure consistent heating. A thermocouple at the inlet sand face allowed monitoring of the temperature of the exiting steam.

Test Preparation

Reservoir Samples

Reservoir materials (core, oil and brine) came from the Primrose reservoir and were donated to the project by Amoco Canada Petroleum Company Ltd. The Primrose reservoir core material used for the tests came from two separate sources. Core for Tests 1 to 11 came from a well located at 10-5-67-W4M from a depth interval of 476 to 496 m. Core material for the remaining Tests 12 to 22 was produced sand taken from a treater associated with the Primrose field. Oil was extracted from the core in a modified Soxhlet apparatus using toluene as the solvent. The extracted core was then heated in an oven to 326°C for about 16 hours to remove the residual hydrocarbons from the mineral matrix. An X-ray diffraction analysis of the bulk and clay fractions of the extracted core from both sources is included in Table 1.

The oil and brine for the test came from Amoco-AEC Ex 16-5-67-4-W4M well. The produced oil, which contained about 25% free and emulsified water, was de-watered and cleaned by heating with toluene addition, then by centrifuging followed by roto-evaporation to remove the toluene. The brine was filtered through a Whatman #5 filter paper. Initial properties of the oil and brine which were used for these tests are also included in Table 1. During the project, two shipments of brine and three shipments of oil from the Primrose site were required in order to complete the tests. The properties of the brine and first two oil shipments were very similar; however, the third oil shipment (used for Tests 19-22) appeared to be much lighter. These values are noted in Table 1. The wide variation in the properties of oil produced from the Primrose reservoir has been noted by Amoco Canada personnel associated with the project[2].

Core Packing and Saturation

The packing procedure for the small-diameter apparatus consisted of manually tamping 50 g increments of dry, clean core into the combustion tube. Gravel packs (coarse silica sand) were placed at both ends of the test core material to prevent core fines from being pushed into the injection or production lines. On completion of the packing operation, an end cap was welded to the end of the tube while ensuring a condition of grain-to-grain stress in the pack. Once the tube was sealed and the heaters and thermocouples were mounted, then the unit was insulated and inserted into the pressure jacket. An annulus pressure of 2.1 MPa (300 psig) was imposed on the tube, the pack was saturated with reservoir brine, and the porosity was calculated; values of this parameter ranged between 37 and 42% for the 22 tests. Brine was then injected at a set rate and the permeability of the core pack was determined; permeabilities fell in the range of 0.5 to 6.5 μm^2. Finally, oil was forced into the packed core from the injection end at a temperature of 80° C until it broke through at the production end. The packing procedure for the 10 cm diameter combustion tube used during Tests 18 and 19 was similar to that used for the 5 cm unit and has been detailed by Moore *et al.*[3] Table 2 gives the average properties of the composite core (Primrose core plus silica sand) prior to each of the tests.

Test Procedures

A total of 22 in situ combustion tube tests were performed to evaluate the enhancement of the in situ combustion process with steam injection. A general summary of the test operating parameters are also summarized in Table 2. The variety of test conditions as shown in this table resulted in the need for five significantly-different operating procedures: (1) the standard dry in situ combustion tube test; (2) standard wet in situ combustion tube test; (3) dry combustion in a previously-steamed core; (4) combustion with steam co-injection following a dry ignition; and (5) combustion with steam co-injection following a hot waterflood.

Standard Dry/Wet Combustion Tube Test Procedure

Tests 1 to 10, 12, 18 and 19 were operated as normal combustion tube tests. The saturated core was first pressurized with helium to the desired run pressure and, at the same time, the annular region between the core and pressure jacket wall was also pressurized with helium. The final pressure of the annulus was set between 700 and 2,100 kPa (100 to 300 psi) higher than the tube pressure. The entire core was then preheated to 80° C in order to establish oil mobility. Once the preheated state was achieved, helium was injected through the core in order to establish gas injectivity, at which time, heaters located at the inlet zone of the combustion tube (Zone 1) were activated and the inlet core temperature increased to 400° C (300° C for wet combustion tests). When the central core temperature reached this desired level, air/enriched air injection was started. In the case of the normal-air tests, this was accompanied with the immediate termination of the helium injection. However, for the enriched-air runs, the helium stream was gradually tapered off over the period of one hour. This gradual enrichment of the feed stream had been previously shown in the laboratory to ensure clean ignitions.

Once ignition was achieved, air/enriched air injection was continued at a constant rate, propagating the high-temperature (or oxidation) front down the length of the core pack. If the test was wet, brine injection was started following the peak of the second zone downstream of the tube inlet. Air (and brine) injection was continued until the front passed the twelfth of the 14 thermocouples (or 10 of the 12 for the larger-tube burns), at which time air/enriched-air injection was terminated and helium was again injected to purge the core and associated piping of air and production gases. Brine injection was continued during the helium purge for the wet tests. Following the helium purge, the system was bled down. There were two reasons for terminating air injection prior to burning completely through the core. First, it allowed for the measurement of hydrocarbon and water saturations both ahead of and behind the main front. Second, for the case of 95% oxygen-enriched air injection, it reduced the possibility of having potentially explosive oxygen/hydrocarbon mixtures in the production system.

Combustion of a Previously-Steamed Core

Tests 11, 13, 14, 15 and 20 were flooded with hot water at 90°C followed by a steamflood to near-residual oil saturation, followed finally by regular dry combustion. At the start, the tube was isolated from the production system and pressurized to the desired back pressure. Field brine was injected for Test 11, while distilled water was utilized in the subsequent tests. No noticeable difficulties with clay swelling or other permeability alterations were noted during the distilled-water tests. The water injection rate was approximately 222 cm^3/h, representing a flux of 0.12 m^3/m^2h, or an interstitial velocity of about 30 cm/h (5 mm/min).

The next stage of each test was the performance of a steamflood to a near-residual oil condition. The general procedure followed was to reduce the water rate by half, and to increase the steam generator temperature to 20° C above the saturated-steam temperature at the given test pressure. When the desired temperature level was reached and had stabilized, the superheated-steam injection rate was increased to 222 ml/h (water equivalent) and was maintained at this level while the steam bank was propagated through the core. A differential temperature of 1° C at the wall was maintained in all zones. The oil and water saturations in the core following the steamflood are also included in Table 2.

On completion of the steamflood, Zone 1 was placed on set point control at 400° C (Tests 11, 13, 14 and 20) or 250° C (Test 15), and Zones 2 to 14 were placed on set point control at 90° C (Tests 11, 13, 14 and 20) or 225° C (Test 15). Helium was then injected through the core while the ignition zone (Zone 1) was increased to the desired ignition temperature; when this was achieved, oxygen flow through the core was gradually initiated while the helium flow was slowly reduced. Clean, vigorous ignitions were observed on all five tests. Oxygen injection continued until the combustion front reached Zone 12. At this time, oxygen was terminated and the helium flow was re-established in order to purge the system of oxygen and combustion gases.

Steam Co-Injection Following a Dry Ignition

The procedure used for Tests 16 and 17 were identical to those used for the standard wet combustion tests described previously. The only difference was that slightly-superheated steam (made from distilled water) rather than liquid brine was injected into the core following the advance of the combustion front past Zone 2.

Steam Co-Injection Following a Waterflood

The procedure developed for Tests 21 and 22 had its basis in the method used for the pre-steamed tests (Tests 11, 13, 14, 15 and 20), which was described previously. Following the waterflood and the heating of the steam generator, and at the same time that the water injection rate was returned to 222 ml/h, enriched-air co-injection was started. The tests were run at high water/oxygen ratios. Following the temperature peak of Zone 12, enriched-air injection was terminated, and shortly after, the power to the steam generator was shut off. Water injection was continued for approximately two more hours, then the system was depressurized.

Data Acquisition and Sample Collection

During each phase of the test, produced liquid samples were manually collected and saved for post-test analysis. During the combustion phase, effluent gases were metered and gas compositions determined every 0.5 hours using a gas chromatograph. Temperatures were recorded every 15 minutes, and whenever any zone temperature peaked. Pressures, gas volumes and water injection volumes were recorded every 0.5 hours.

RESULTS

Combustion Mode

Based on the temperature data, Tests 9 and 10 were the only runs which operated in the superwet combustion mode. All of the other tests exhibited distinct peak temperatures in the ranges typical of dry and normal-wet operation.

Stabilized Combustion Parameters

Stabilized oxygen requirements for the 22 tests are summarized in Figure 3 as a function of the water/oxygen ratio. Tests which exhibited multiple stabilized periods are represented by the one occurring latest in the test. When reviewing the data, it is important to remember that a number of operating parameters have been varied in addition to the water/oxygen ratio. One of these key parameters is the oxygen flux, which was evaluated over the range from 6.5 to 20.5 $m^3(ST)/m^2h$ to examine its effects and to ensure that the dry combustion tests did not undergo severe thermal quenching due to the heat capacity of the combustion tube. With this in mind, the data in Figure 3 illustrate several important concepts. First, there is a relatively-wide spread in the stabilized oxygen requirements for the dry combustion tests; this is typical of the dry combustion behavior of oils from other reservoirs.[4]

While fewer tests were involved, the oxygen requirements for the normal-wet combustion tests fall within a relatively-narrow region, in spite of the variation in the operating parameters. The third point is the benefit of steam as compared to water injection for the tests performed with the water/oxygen ratio (which is equal to the steam/oxygen ratio when the steam injection rate is based on the cold water equivalent) between 7.5 and 15 kg/m^3(ST). The two tests involving cold water injection operated in the superwet combustion mode (based on their maximum temperatures), but the oxygen requirements were significantly greater than those for the normal-wet test. Oxygen requirements for the superwet tests were based on the vaporization front (trailing edge) velocity, and the high apparent oxygen requirements relate to energy generation in the region of the vaporization front, which was due to the presence of a significant concentration of reactive residual hydrocarbon within the upstream region of the steam-bank type oxidation zone. The two tests involving steam co-injection with the enriched air at a steam/oxygen ratio of approximately 11.6 kg/m^3(ST) exhibited distinct combustion zones, hence the oxygen requirements were based on the high-temperature zone leading edge velocity as is the usual procedure for normal-wet combustion. These two tests had oxygen requirements which were similar to those for the superwet combustion of Athabasca Oil Sands.[4]

It is of interest to note that three of the steam-enriched air tests fall on a trend line which appears to correlate with the oxygen requirements for the two large-diameter combustion tube tests; this is related to the lower relative energy load on the reaction kinetics for this tube. While the small-diameter combustion tube is equipped with more heating zones, its size results in a much higher ratio of the heat capacity of the radial region in contact with a given length of reaction zone to the volume of that zone. Steam injection in the small tube appears to compensate for this effect, as does the use of a high preheat temperature. This is apparent since the oxygen requirements for the small-diameter Test 15 were almost identical to those for the large-diameter Test 18. With the exception of Test 15, steamflooding of the cores prior to dry combustion did not have a significant effect on the stabilized oxygen requirements.

Figure 4 illustrates the stabilized oxygen requirements for all of the tests which were performed in the dry-combustion mode using the small-diameter combustion tube. The requirements are plotted as a function of the effective oxygen partial pressure, which was based on the core-outlet total pressure and on the effective oxygen concentration in the injection gas corrected for helium contamination due to leakage from the annulus. A review of the tests which did not involve steam injection either prior to or during the combustion phase suggests that there is a trend of minimum oxygen requirements within the range of oxygen partial pressure from 2,000 to 4,000 kPa, and increasing oxygen requirements with increasing oxygen partial pressure as it rises above 4,000 kPa. This effect is not as significant as was observed for Athabasca Oil Sands by Moore *et al,* as the oxygen flux for that test series was significantly lower than those for the Primrose runs.[5] The Primrose data indicate that, so long as the oxygen flux is maintained at a sufficient level that the primary oxygen consumption reaction is that of high-temperature combustion, then the combustion kinetics are relatively insensitive to the oxygen partial pressure. The stabilized oxygen requirements for the five tests involving steamflooding prior to dry combustion are not significantly different from the requirements for the tests which were conducted on 90° C preheated cores. Because four of the five tests involving steam injection prior to combustion experienced helium dilution due to leakage from the annulus, there is a slight uncertainty with regards to the effective oxygen partial pressure for all but the test having the highest partial pressure.

Stabilized oxygen/fuel ratios for all of the tests are shown as a function of the stabilized water/oxygen ratios in Figure 5. For the dry tests (water/oxygen ratio of 0.0 kg/m^3(ST)), the majority of these ratios fall in the region of 2.4 m^3(ST)/kg (equivalent air/fuel ratio of 11.4 m^3(ST)/kg), with the combustion-following-steam tests showing no appreciable variation. The two tests exhibiting significantly higher oxygen/fuel ratios were both dry-combustion tests using 95% oxygen-enriched air on cores which were preheated to 90° C. Problems with the gas chromatograph could have been the reason for the highest value at 9,900 kPa, but the large oxygen/fuel ratio for the test at 4,000 kPa is believed to be reflective of the oxidation kinetics.

The majority of the wet (water and steam injection) tests were performed at 10.3 MPa using enriched air. In general, the oxygen/fuel ratios were slightly larger than the dry combustion values, although the highest values observed are in the same region as that for the dry combustion test at 10.3 MPa. Of the three wet tests having oxygen/fuel ratios in excess of 3.0 kg/m^3(ST), the two runs at water/oxygen ratios of 11.5 and 33.5 kg/m^3(ST) involved steam co-injection, while the test at a water/oxygen ratio of 4.2 kg/m^3(ST) was performed in the large-diameter combustion tube using liquid water injection. Product gas holdup within the combustion apparatus was very high during the two steam co-injection tests with the large oxygen/fuel ratios, which may account, in part, for the high values.

The test having the lowest oxygen/fuel ratio operated in the superwet mode. Because of the operating pressure (10.3 MPa), the temperature within the steam-bank type oxidation zone was sufficiently high to generate high concentrations of carbon dioxide in the product gas. The stabilized carbon dioxide concentration for this test was

84.5%, which was the second-highest value observed over the 22 test program.

Stabilized apparent atomic hydrogen/carbon ratios are presented in Figure 6. All five of the normal-air tests and eight of the 95% oxygen enriched-air tests exhibited apparent atomic H/C ratios in the region of 1.7. Apparent atomic H/C ratios in the region of 6.0 were observed for four of the 95% oxygen tests. The test exhibiting the highest H/C ratio involved the co-injection of steam, but the very high value for this test may in part reflect product gas holdup within the system. As was observed for the related oxygen/fuel ratio, the test having the lowest apparent atomic H/C ratio operated in the superwet mode.

Based on conventional high-temperature stoichiometry for high-pressure combustion, the stabilized (CO_2 + CO)/CO ratio should be an important parameter; however, attempts by the authors to correlate this parameter with combustion performance have not been successful. This is illustrated in Figure 7, which shows a good correlation with oxygen partial pressure based on the feed gas concentration for oxygen pressures up to 6,000 kPa. This relationship was obviously lost for the 10.3 MPa tests, and no successful correlation of the high-pressure test data was achieved. Experience with other reservoirs suggests that high stabilized (CO_2 + CO)/CO ratios are observed following a period when a test exhibits significant oxygen uptake by low-temperature oxidation (LTO) reactions. This generally occurs when a highly-saturated liquid bank forms, thus restricting the gas relative permeability within the oxidation zone. The authors generally associate high (CO_2 + CO)/CO ratios with the combustion of a pre-oxidized oil, but it is difficult to generalize this parameter into simple correlations.

Overall Combustion Parameters

Stabilized combustion parameters are generally preferred for comparing the performance of combustion tests operated under different sets of conditions. This is especially true of wet tests, if they are ignited in the dry-combustion mode. In this case, overall parameters represent an average of the two operating regimes. Stabilized combustion parameters as presented previously provide a good representation of the performance of dry combustion tube tests so long as the tests exhibit good stability over the total run duration. For unstable tests, parameters determined during the so-called "stabilized" period may be unduly influenced by performance during earlier phases of the test. For example, tests which exhibit very slow oxidation-front velocities during the period immediately following ignition will often have very high velocities during later periods of the burn due to the consumption of oxygen stored chemically in the oil during the slow-velocity period. Because overall combustion parameters are not subject to bias through selection of a time period which is assumed to represent stabilized burning, a comparison of the overall and stabilized values provides a useful measure of the degree of stability of the test during the "stabilized" period.

Figure 8 presents the overall reacted oxygen requirements for the 22 combustion tests as a function of the average water/oxygen ratio. The average water/oxygen ratio is defined as the mass of water injected during the period of oxygen injection divided by the injected oxygen. The overall reacted oxygen requirements are based on the volume of oxygen reacted and the location of the combustion zone at the time that oxygen injection was terminated, thus they include oxygen which is stored in the swept portion of the core. The overall oxygen requirements are in good agreement with the stabilized values, and it can be concluded that the stabilized values are not highly biased by the selection of the stabilized period.

The nominal operating procedure for the combustion tube tests was to terminate oxygen injection at the time that the combustion front had swept 80% of the total core length. Figure 9 shows the liquid oil recoveries (calculated by difference as discussed below) in terms of the overall water/oxygen ratios. These oil recoveries are based on the mass of oil in the core prior to the start of any fluid (gas or water) injection, hence the recovered oil includes the amount recovered during the steamflood for the combustion-following-steam tests. The two dry-combustion tests showing the lowest recoveries were normal air runs conducted at 4.1 MPa. Both of these tests experienced premature exhaustion (due primarily to low oxygen fluxes), therefore the amount of core swept was less than for the other tests. In general, the tests which exhibited the highest measured oil recoveries were the two tests performed in the large-diameter combustion tube. This was an expected result, as the large-diameter tube is less sensitive to thermal quenching and thus to the development of conditions leading to oxygen uptake by low-temperature oxidation reactions. The tests having the lowest recoveries were the two tests which operated in the superwet mode and the series of tests involving steam injection either prior to dry combustion or as co-injection with the 95% oxygen gas. The overall hydrocarbon mass balances suggest that the measured oil recoveries for the tests involving steam may be low due to the loss of light liquid components, hence the need for liquid oil recoveries calculated by difference. Assuming that the loss of light oil was the reason for the discrepancy in the mass balance, it is clear that steps must be taken to prevent the loss of light oil fractions from a field combustion project in the Primrose reservoir.

Combustion Following Steam Tests

As was stated previously, the oil recovery for the tests involving steamflooding prior to dry combustion included the oil recovered during the steamflood. Figure 10 shows that, for all five tests involving steamflooding prior to dry combustion, the bulk of the oil was recovered during the steamflood. Information on the steamflood phase for four of the five tests is provided by Moore *et al*, but it is apparent from Figure 10 that the tests were not steamed to a true steamflood residual condition.[5] The recovery curves show that the amount of oil recovered during the combustion phase was dependent on the steamflood residual. This is, of course, an expected result, as the apparent fuel consumed during the combustion phase of each run was relatively independent of the initial oil saturation. What these tests showed is that, while the combustion zones were very stable, the amount of oil which could be recovered from highly-depleted zones may not be sufficient to justify the cost of installing combustion equipment. The key to a successful combustion process in a previously-steamed reservoir is to utilize combustion as an energy generator, and to take steps to contact the more highly-saturated zones within the heated area. This means that the fireflood process would be best operated in a cyclic, as opposed to continuous, air injection mode. Alternating slugs of air (or oxygen) and water (or steam) has considerable merit for application in previously-steamed reservoirs. These are not new observations, as BP Canada Resources Ltd. and AOSTRA previously utilized many of these concepts in the development of their Pressure Up-Blow Down (PUBD) process for their Marguerite Lake Combustion Project in the Cold Lake reservoir.[6]

Co-injection of Steam and Oxygen Tests

Figures 11 and 12 illustrate the effect of the co-injection of oxygen and steam at 10.3 MPa. Figure 11 gives the as-measured oil production as a function of the oxygen injected. Of the five tests shown, Test 7 was dry (base case), Tests 9 and 10 were the two superwet tests involving the co-injection of liquid water and 95% oxygen-enriched air at 90° C, and Tests 17 and 22 involved the co-injection of slightly superheated steam with the oxygen. The stable water(steam)/oxygen ratios for these runs are detailed in Table 2. Figure 12 presents the same as-measured oil production curves, but as a function of the water (or steam) injected. In this plot, Test 7 is replaced with Test 20, which was run purely as a steamflood until over 70% oil recovery was achieved.

On examination of Figure 11, it can be seen that the rate of oil displacement in Test 9 was approximately the same as that of the dry combustion test. This is not an expected result, based on the fact that Test 9 operated in the superwet mode, which would normally have provided accelerated oil recovery for a given volume of oxygen injected. The behavior is, however, consistent with the elevated oxygen requirements for Test 9 as shown in Figure 3. Test 10 illustrates the acceleration in oil recovery rate which is normally associated with superwet combustion. This test also exhibited high apparent oxygen requirements; however, the oil produced versus oxygen injected curve indicates that the slow trailing-edge velocity for Test 10 does not translate to a reduction in the oil recovery at a given pore volume of oxygen injected. This suggests that the oil is mobilized well downstream of the trailing edge of the oxidation zone. Tests 10 (water injection) and 17 (steam co-injection) were performed at similar water/oxygen ratios, and their recovery curves are very similar up to 70% oil production, when the benefit of oxygen injection becomes very apparent. This again suggests that the high apparent oxygen requirements for Test 10 result from the use of the trailing edge, or vaporization front, for defining the location of the oxidation zone. Test 22 produced the most oil for the least pore volumes of oxygen injected, but this is to be expected given the high steam/oxygen ratio for this test.

These same curves, as illustrated on Figure 12, show that Test 22 displaced oil at a corresponding rate to pre-steamed Test 20, and that similar behavior up to 70% oil production can be observed for Tests 10 and 17, and, to some extent, Test 9.

Both Figures 11 and 12 demonstrate that Test 17 offered the greatest recovery for the least amount of aggregate fluids injection. While the relative economics of injecting steam versus oxygen must be examined, the conditions of Test 17 offer a desirable operating state. Test 22 demonstrated good recovery and represents a potentially valuable enhancement of the steamflood process. Despite the high water/oxygen ratio, in general it was found that the steam-oxygen co-injection process maintained high peak temperatures (> 500° C) and therefore shows potential for delivering high-quality steam at large distances from the injection well in a field application.

General Observations

When reviewing the data for the Primrose reservoir, it is important to note that the injection oxygen flux was maintained sufficiently high so as to promote stability of the high-temperature combustion zone during the dry-combustion tests. The combustion performances exhibited by the Primrose tests correspond to conditions where low-temperature oxidation reactions are not dominating the performance of the process. Even under this condition, it is apparent from the spread in the combustion parameters for the 10.3 MPa runs that the kinetics of fireflooding are much less stable at high-pressure conditions. This fact must be kept in mind when evaluating the application of high levels of oxygen enrichment in a field project.

The behavior of the two superwet tests at 10.3 MPa demonstrates the complex nature of the process when operating at water/oxygen ratios which are close to the value corresponding to the transition between normal and superwet operation (optimal wet combustion). From the perspective of oil recovery versus oxygen injected, Test 9 behaved as if it were a dry test, while Test 10 performed as a steam co-injection test. Both of these tests exhibited higher injection oxygen requirements than the dry combustion tests, which, as was indicated previously, relates to the velocity of the trailing edge or vaporization front. While the slow rate of advance of the oxidation zone (vaporization front) did not have a highly detrimental effect on the oil recovery for the two laboratory tests, it has considerable significance when the process is applied in the field. The slow rate of advance of the oxidation zone implies that the region over which oxygen is utilized could become very spread out. This increases the relative percentage of the generated energy which will be lost to the surrounding strata. The combination of oxygen consumption over a large region (which translates to lower energy generation per unit volume) and the increased heat losses may ultimately lead to premature exhaustion of the oxidation reactions. In view of this behavior, field projects should not be designed for operation at water/oxygen ratios in the vicinity of the optimal wet condition.

Steam co-injection with the 95% oxygen stream was very effective at stabilizing the combustion process, and this type of process has considerable merit for application in heavy oil reservoirs. The combustion kinetics are stabilized, as the steam promotes operation in the high-temperature combustion mode by helping to maintain a gas saturation within the highly liquid-saturated (oil bank) region. The steam process is improved by the in situ energy generation, which maintains steam quality over a greater distance from the injection well.

CONCLUSIONS

The conventional combustion tube tests showed that injection oxygen requirements varied between 50 and 80 $m^3(ST)/m^3$ for the Primrose cores. The largest variation in combustion parameters was observed at 10.3 MPa, which relates to the greater number of tests performed at this pressure, as well as to the destabilizing effect of high oxygen partial pressures. Two superwet runs at 10.3 MPa demonstrated that operation at water/oxygen ratios between 9.5 and 13.8 $kg/m^3(ST)$ is not recommended. Although very stable operation was observed for the tests involving dry combustion following steam, the amount of oil available for recovery during the combustion phase was small. Steam-oxygen co-injection provided stable operation over a wide range of steam/oxygen ratios, which indicated that there was considerable opportunity for optimizing this type of process.

ACKNOWLEDGMENTS

The parametric study of steam-assisted in situ combustion was undertaken as a jointly-sponsored project between the CANMET/ERL division of the Canadian Federal Government's Department of Natural Resources and nine companies from industry: Amoco Canada Petroleum Company, BP Canada Resources (now Talisman Energy), Canadian Liquid Air, Linde-Union Carbide (now Praxair Canada), Mobil Oil Canada, Murphy Oil Company, Petro-Canada Resources, Saskoil (now Wascana Energy) and Unocal Science and Technology. The authors gratefully acknowledge the contributions of both government and industry to this project. Special thanks are due to Dr. Bob Lee of Canadian Liquid Air (Montreal), for his advice and encouragement on the tests which evaluated the co-injection of steam and oxygen, and to Amoco Canada Petroleum Company for supplying the core, oil and brine for the project.

REFERENCES

1. Sibbald, L. R., R. G. Moore, D. W. Bennion, B. J. Sibbald and M. G. Ursenbach: "In-Situ Combustion Experimental Studies Using a Combustion Tube System With Stressed Core Capability," *AOSTRA J. of Research*, v. 6, No. 3, Summer 1990, pp. 171-184.
2. Jensen, E., Personal Communication, 1992.
3. Moore, R. G., D. W. Bennion, J. D. M. Belgrave, D. N. Gie and M. G. Ursenbach: "New Insights into Enriched-Air In Situ Combustion," *JPT*, v. 42, No. 7, July 1990, pp. 916-923.
4. Ursenbach, M.G., R. G. Moore, D. W. Bennion and J. D. M. Belgrave: "Laboratory In Situ Combustion Behavior of Athabasca Oil Sands," CIM Paper No. 93-10-25, *Proceedings of the 5th Saskatchewan Petroleum Conference*, Regina, Saskatchewan, Oct. 18-20, 1993.
5. Moore, R.G., J. D. M. Belgrave, S. A. Mehta, M. G. Ursenbach, P. A. Gomez and K. N. Jha: "In Situ Combustion Performance in Steam Flooded Heavy Oil Cores," CIM Paper No. 92-78, Proceedings of the CIM 1992 Annual Technical Conference, Calgary, Alberta, Jun. 7-10.
6. Hallam, R.J. and J. K. Donnelly, J.K: "Pressure-up Blowdown Combustion: A Channeled Reservoir Recovery Process," SPE Paper No. 18071, Presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, TX, Oct. 2-5.

TABLE 1

Initial Properties of Primrose Reservoir Material

I. CORE TESTS 1-11/TESTS 12-22

A. X-Ray Diffraction

Bulk Fraction		Clay Fraction	
Quartz	26%/57%	Montmorillonite	4%/11%
Feldspar	63%/33%	Chlorite	5%/6%
Clays	11%/11%	Illite	17%/35%
		Kaolinite	50%/48%
		Mixed Layer	24%/0%

B. Density 2.6259 g/cm^3

II. OIL TESTS 1-18/TESTS 19-22

A. Ultimate Analysis (Mass %)

Carbon	86.33%/81.90%
Hydrogen	10.71%/10.92%
Nitrogen	0.58%/0.51%
Sulfur	4.78%/4.73%

B. Density 0.9953 g/cm^3 / 0.9796 g/cm^3

C. Viscosity (mPa·s)

80°C	556/129
95°C	236/75
110°C	107/46

D. Pseudo Components (Mass %)

400°C Distillate	22.34%/23.61%
400°C Residue	56.06%/59.52%
Asphaltenes	21.60%/16.87%

III. BRINE

A. pH 8.72

B. Anions, Cations (mg/l)

CO_3^{--}	50	K	110
HCO_3^-	180	Ca	50
Cl^-	5300	Na	4100
SO_4^{--}	8	Mg	40
		Fe	<1

C. Total Solids 8720 mg/l

D. Total Carbon 3550 mg/l

TABLE 2

Operating Conditions

Test	Back Pressure (MPa)	Initial Saturation Oil (%)	Initial Saturation Water (%)	Ignition Temperature (°C)	O_2 in Bottled Feed Gas (mole %)	O_2 in Feed Gas Including Leaks (mole %)	Average Injection O_2 Flux (m^3(ST)/m^2h)	Stable Water/Air Ratio (kg/m^3(ST))	Operating Procedure Type**
1	4.1	60.8	39.2	405	21.42	21.42	19.00	0	1
2	10.3	80.7	19.3	400	21.52	21.52	10.30	0	1
3	4.1	74.1	25.9	400	21.54	21.54	6.50	0	1
4	10.3	80.2	19.8	298	22.27	22.27	10.90	4.76	2
5	4.1	80.3	19.7	300	23.16	23.16	13.80	3.84	2
6	4.1	74.0	26.0	416	95.45	95.45	9.77	0	1
7	10.3	72.3	27.7	400	95.32	95.32	12.54	0	1
8	10.3	74.2	25.8	300	95.25	95.25	12.49	4.26	2
9	10.3	70.5	29.5	300	95.25	95.25	12.49	9.50	2
10	10.3	80.2	19.8	300	95.25	95.25	12.49	13.80	2
11	4.1	26.9*	73.1*	400	95.25	76.50	12.47	0	3
12	10.3	75.6	24.4	400	95.47	86.33	28.94	0	1
13	6.2	38.6*	61.4*	400	95.34	76.57	12.48	0	3
14	10.3	42.5*	57.5*	400	95.63	11.52	12.60	0	3
15	4.1	21.8*	78.2*	250	92.00	22.00	12.53	0	3
16	10.3	81.6	18.4	300	95.29	76.59	12.48	5.10	4
17	10.3	74.5	25.5	300	95.15	95.15	12.46	11.50	4
18	10.3	81.2	18.8	400	95.08	95.08	6.76	0	1
19	10.3	80.2	19.8	300	95.17	95.17	6.78	4.23	2
20	10.3	28.7*	71.3*	400	95.08	95.08	12.45	0	3
21	10.3	73.5	26.5	153	94.99	94.99	9.57	11.71	5
22	10.3	70.3	29.7	200	95.04	95.04	2.99	33.50	5

* Saturation at Start of Combustion

** OPERATING PROCEDURE TYPES

1. Dry Combustion, Standard Operating Procedure
2. Wet Combustion, Standard Operating Procedure
3. Waterflood, Then Steamflood Followed by Dry Combustion
4. Dry Ignition, Followed by Co-Injection of Steam and Oxygen
5. Waterflood, Steam Heating to Ignition, Followed by Co-Injection of Steam and Oxygen

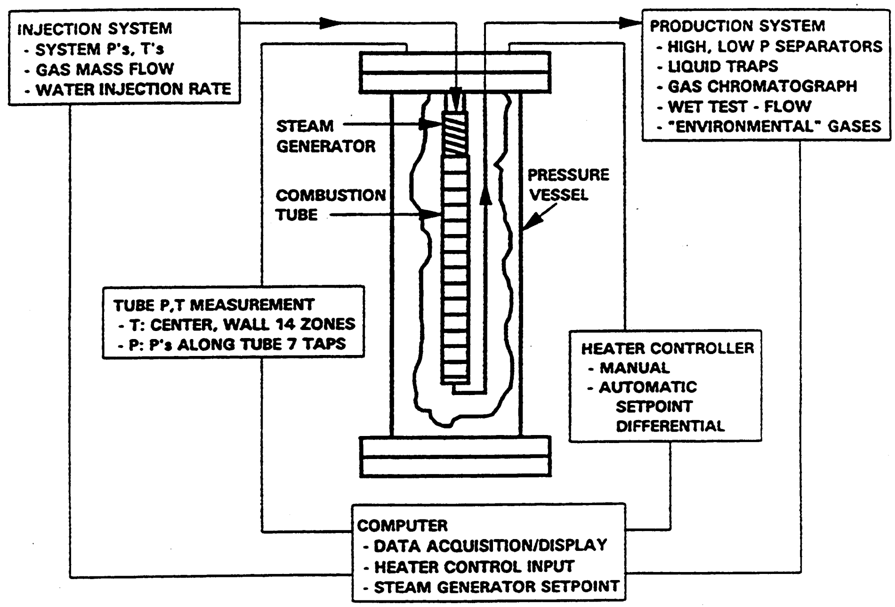


Fig. 1 - Block Diagram of The Combustion Tube System

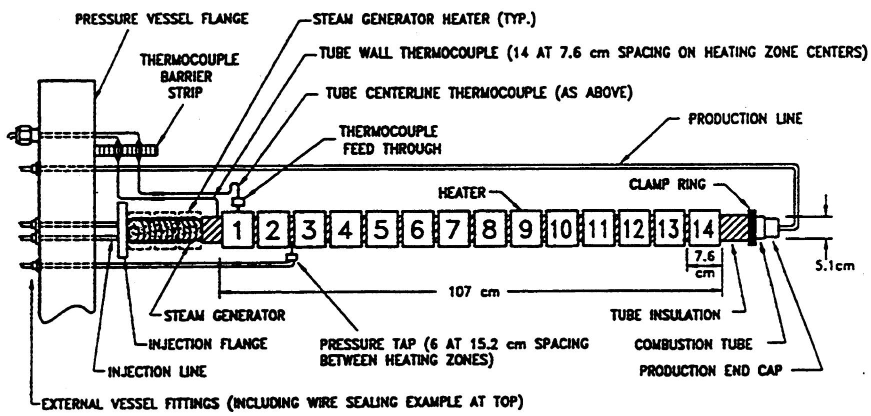


Fig. 2 - Schematic Diagram of the Combustion Tube

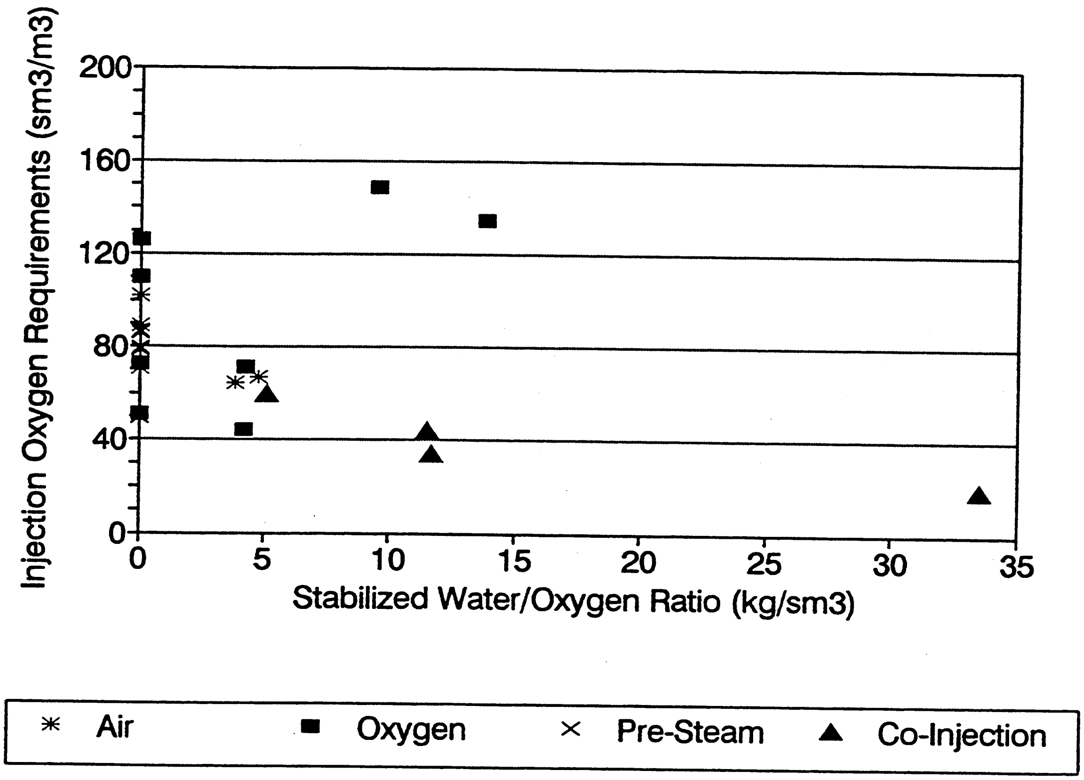


Fig. 3 - Injection Oxygen Requirements vs. Stable Water/Oxygen Ratio (All Tests)

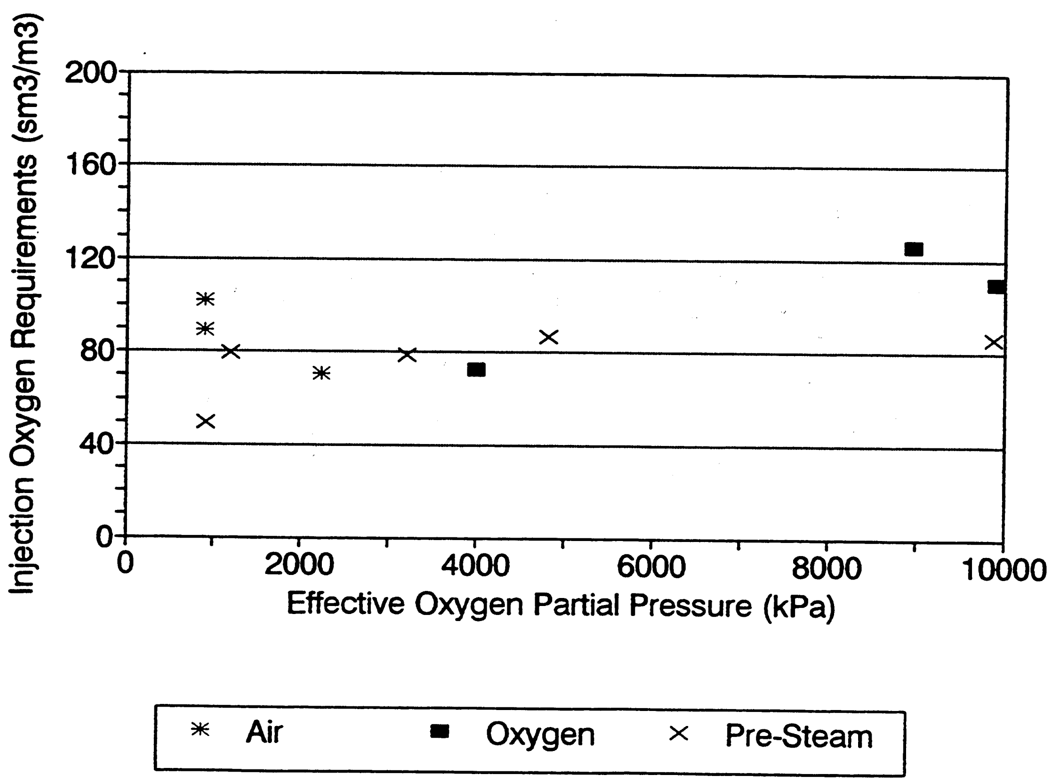


Fig. 4 - Injection Oxygen Requirements vs. Effective Oxygen Partial Pressure (Dry, Small-Tube Tests)

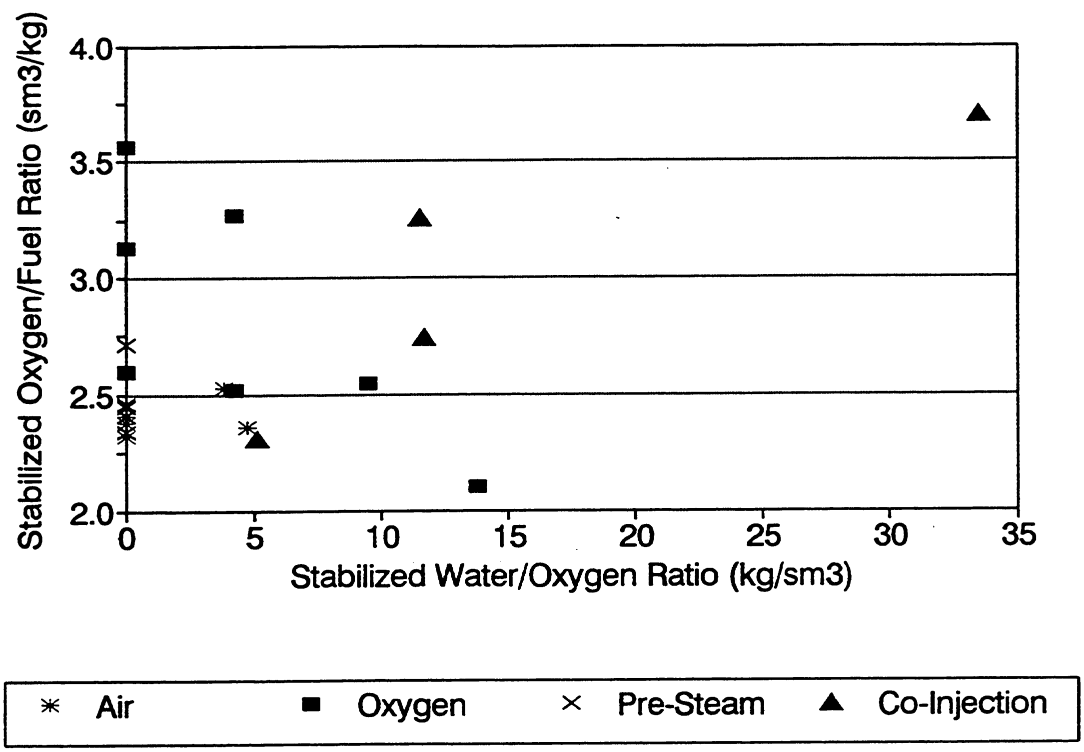


Fig. 5 - Stabilized Oxygen/Fuel Ratio vs. Stabilized Water/Oxygen Ratio

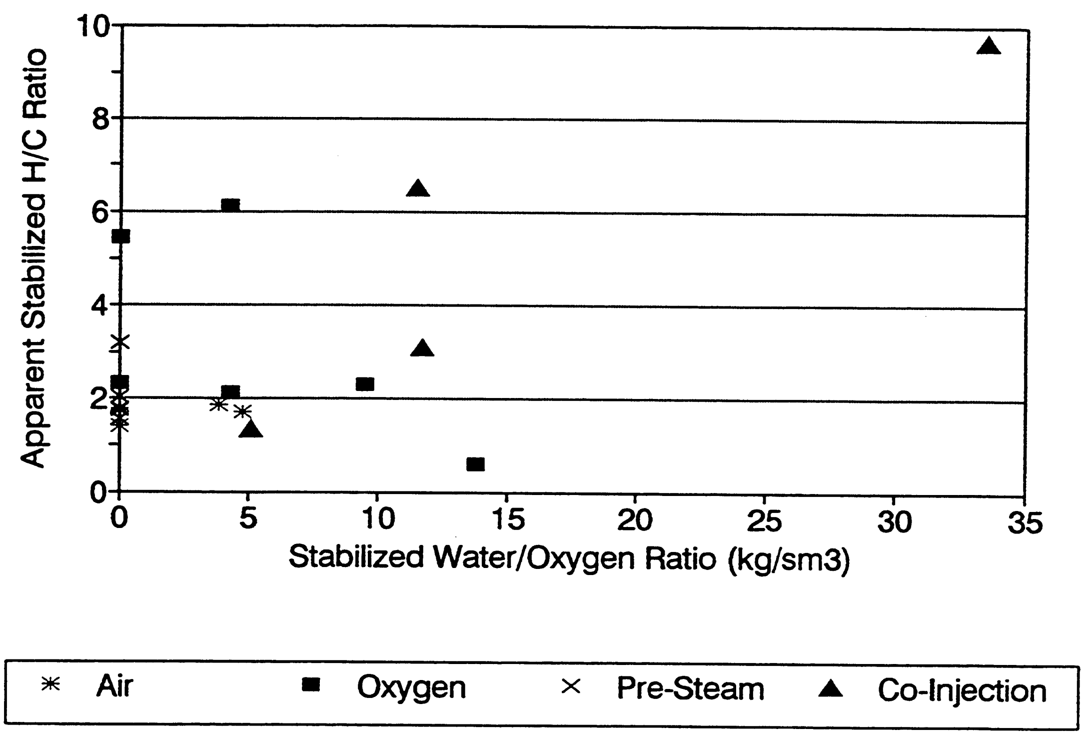


Fig. 6 - Apparent Stabilized H/C Ratio vs. Stabilized Water/Oxygen Ratio

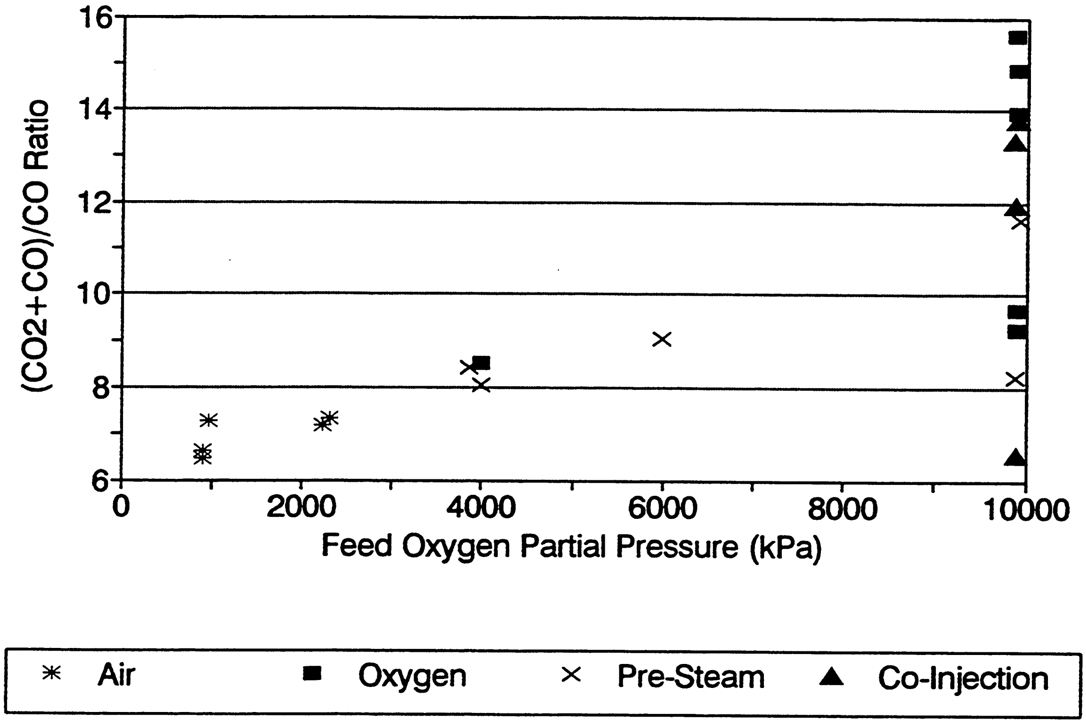


Fig. 7 - Stabilized $(CO_2 + CO)/CO$ Ratio vs. Feed Oxygen Partial Pressure

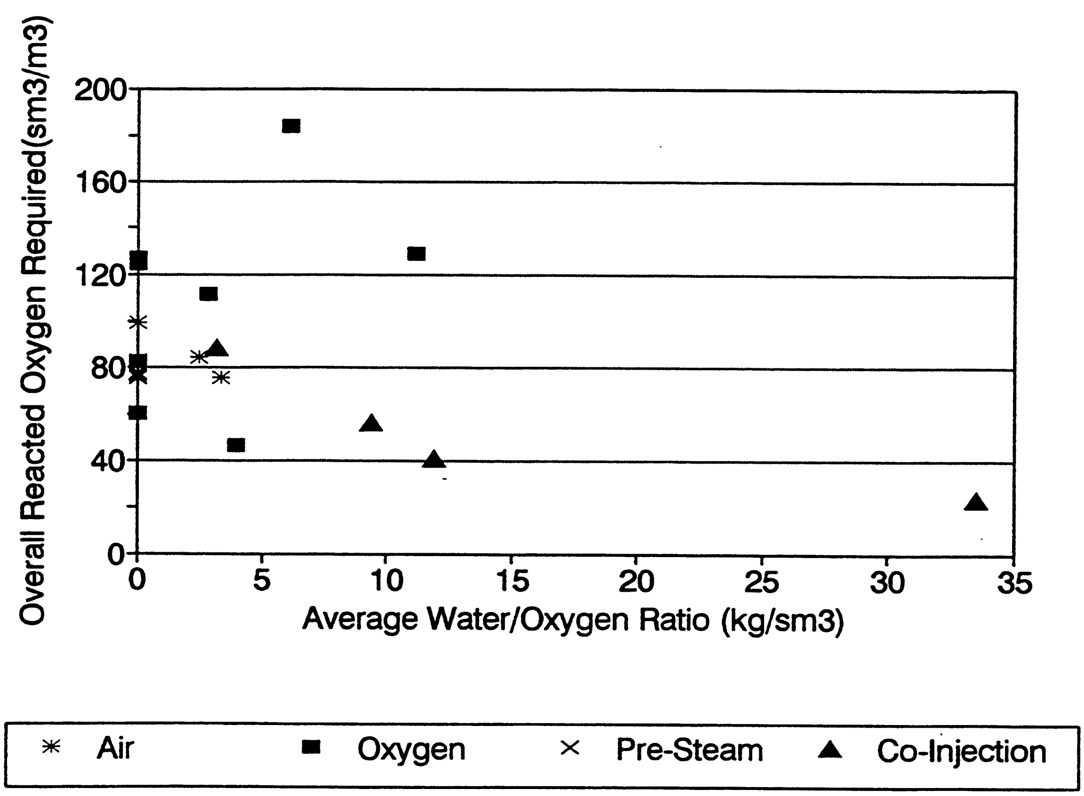


Fig. 8 - Overall Reacted Oxygen Required vs. Average Water/Oxygen Ratio

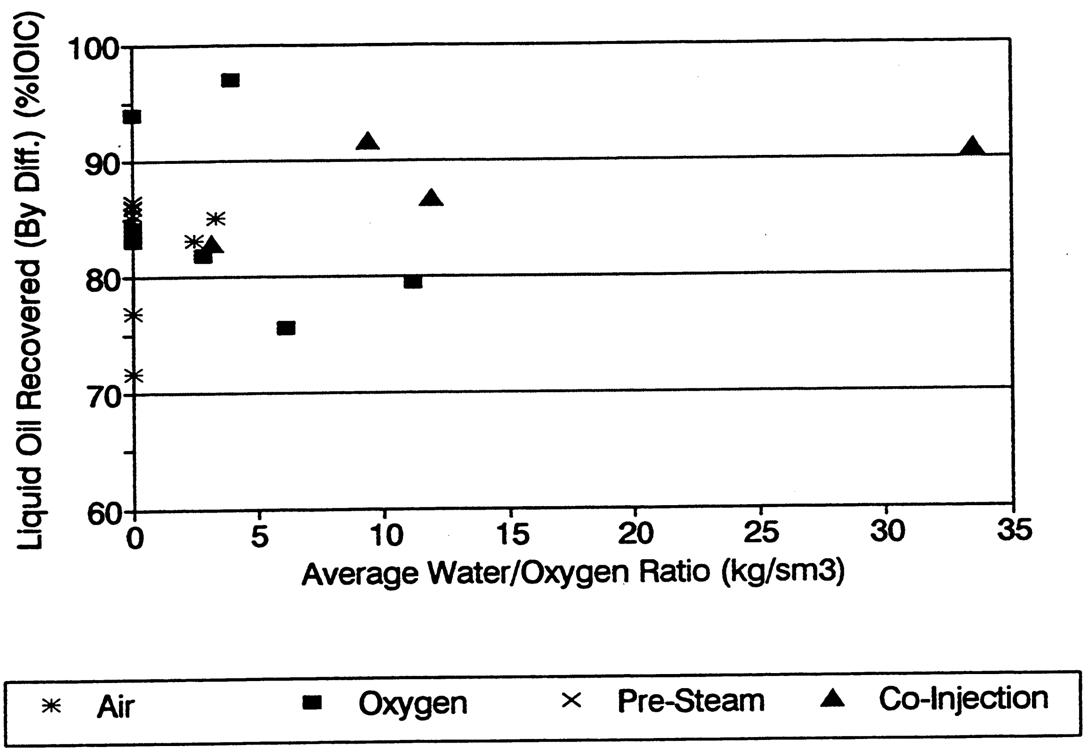


Fig. 9 - Liquid Oil Recovery by Difference vs. Average Water/Oxygen Ratio

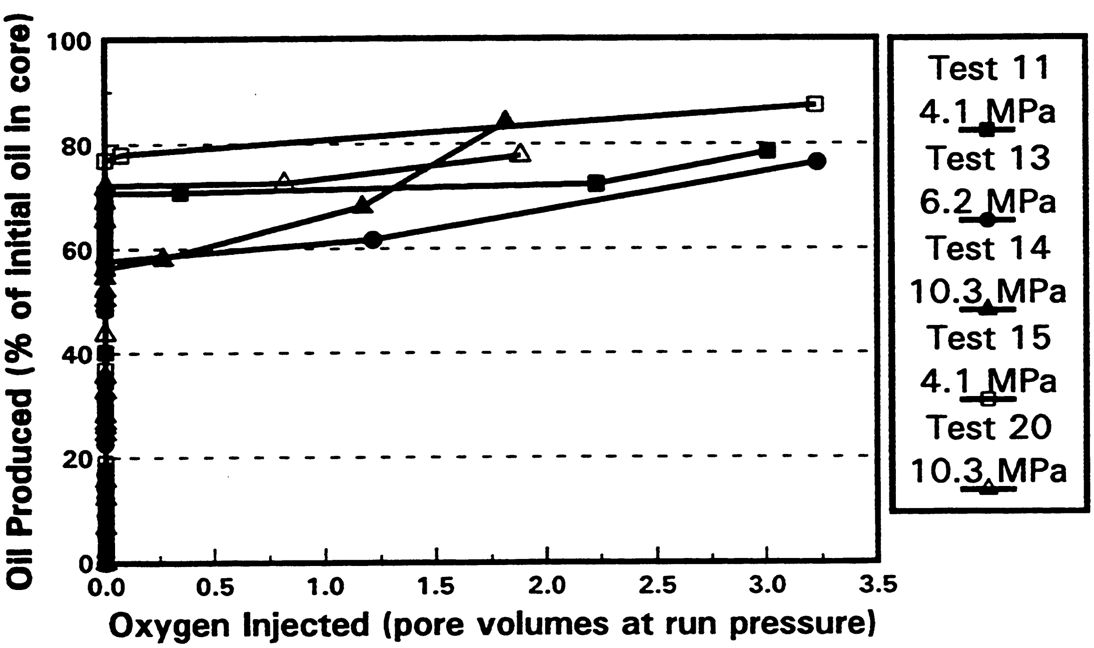


Fig. 10 - Oil Produced vs. Oxygen Injected - Effect of Pressure on Pre-Steamed Cores

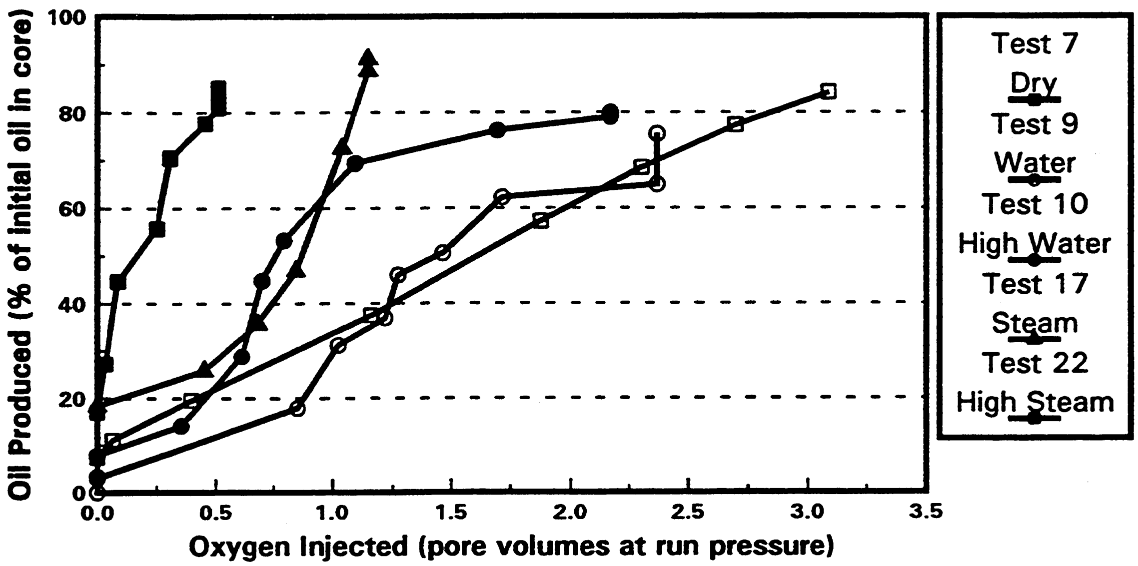


Fig. 11 - Oil Produced vs. Oxygen Injected - Effect of Operating Procedure

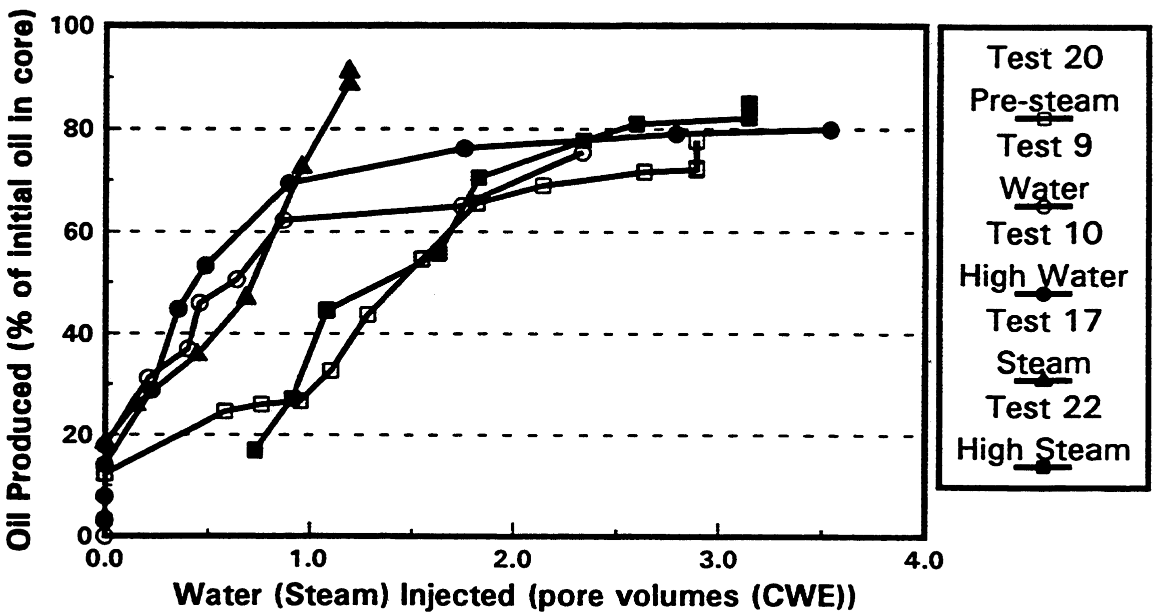


Fig. 12 - Oil Produced vs. Water Injected - Effect of Operating Procedure

The Use of Air Injection to Improve the Double Displacement Processes

by M. R. Fassihi and T. H. Gillham, Amoco Production Company, Houston, Texas

Originally presented as Society of Petroleum Engineers paper No. 26374 at the 68th Annual Technical Conference and Exhibition of SPE held in Houston, Texas, October 3-6, 1993. Copyrighted by Society of Petroleum Engineers, Inc., 1993.

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

ABSTRACT

The Double Displacement Process (DDP) has been defined[1] as the gas displacement of a water invaded oil column. The purpose of injecting gas into a watered out oil reservoir is to recover more oil by creating a gas cap and thereby allowing gravity drainage of the liquids to occur. During 1994, Amoco Production Company, in partnership with the United States Department of Energy, will initiate the first project to combine air injection with the DDP. Due to the relatively low cost and potential for accelerated recovery, this unique IOR process may prove to be economically viable in low price environment. This report introduces the project by describing: (1) the initial project design, (2) core and fluid property tests, (3) details of the scoping reservoir models, (4) projected production performance and (5) safety considerations.

Modeling of the DDP with air indicated that injection/production rates are predominant factors on the performance of the DDP and need to be optimized. Also, gravity drainage is enhanced due to mobilization of oil by the thermal front. It is shown that the in situ generated flue gas strips the light hydrocarbon components. These appear as natural gas liquids (NGL) in the producing stream. Experimental results indicate that the oxygen in the injected air will spontaneously combust with the residual oil saturation in the reservoir. Compared to nitrogen injection, air injection should yield the same cumulative oil at a lower cost.

The use of air injection with the DDP will be applicable in watered out oil reservoirs which have both: (1) sufficient reservoir temperature to accelerate oxygen consumption, and (2) low oil viscosity in conjunction with sufficient bed dip and permeability for gravity drainage to occur.

INTRODUCTION

During 1994, Amoco Production Company in partnership with the United States Department of Energy will initiate an air injection project in the West Hackberry Field, located in the Cameron Parish, Louisiana near Lake Charles (see Fig. 1). The goals of this project are to: (a) displace the oil by gravity drainage and (b) push the encroached aquifer toward its original water-oil contact The Amoco/DOE partnership comes through the DOE's Class 1 mid-term program for development of advanced recovery technologies for fluvial-dominated deltaic oil reservoirs. Through this partnership, DOE will pay 50% of the project costs in return for transferring this technology to the outside companies.

Air injection for oil recovery from deep light oil reservoirs has been recommended for the following reasons.[2] First, a gas is needed to pressurize the reservoir or maintain its pressure during depletion. Compared to other gases, air is a better choice for injection because it also react with oil to form flue gas (85% N_2, 15% CO_2) in situ. Compressing air is generally cheaper than injecting nitrogen or CO_2. Also, because of mass transfer between the oil and flue gas or air at reservoir conditions, the light hydrocarbon components are stripped off the oil. These components appear as NGL in the producing gas stream.[3] Because of in situ combustion, part of the residual oil to gas is mobilized and moves towards the producing well.

References and illustrations at end of paper.

Generally, the deeper and warmer reservoirs are better candidates. Higher pressure enhances miscibility and higher temperatures improves oxygen utilization. Finally, air is available in remote locations so lack of solvent is not a problem in this process.

The process of injecting a gas into a water invaded oil column is called the Double Displacement Process (DDP).[1] The two displacements refer to oil displacement by gravity drainage and water displacement by the gas/oil movement down structure. When air is injected, upon ignition of the oil, a combustion front is created around the injector. The mobilized oil by the combustion front is expected to add to the thickness of the oil column created by gravity drainage. The DDP with air will be tested for the first time at West Hackberry.

REVIEW OF PREVIOUS GRAVITY DRAINAGE PROJECTS

There have been numerous gas injection projects for gravity drainage in different fields. Two projects that share similar reservoir properties or recovery processes with West Hackberry field are discussed below.

West Hawkins

Exxon has been injecting a mixture of natural gas and N_2 into this East Texas field since 1975.[1] The reservoir and fluid properties are listed in Table 1. The east segment of this field was under a strong water drive that pushed the oil into the gas cap. To arrest this migration and also to recover the oil in the watered out west segment, a gas injection program was initiated. Through the application of the DDP, Exxon expects to lower the oil saturation from 35% to 12%. The laboratory test on Hawkins cores indicated that the minimum residual oil saturation to gas is essentially the same for both secondary and tertiary gas displacements.[1]

Weeks Island

Shell operated an immiscible gravity stable CO_2 flood (diluted with methane) pilot at Weeks Island in Louisiana.[4] The pilot lasted from 1978 until 1989. The test was carried out in a deep (13,000 ft) and hot (225° F) fault block with a 26 dip and a structure similar to West Hackberry. The reservoir and fluid properties are provided in Table 1. The post coring of the gas flooded areas showed that the oil saturation had decreased from 22% to 1.9%. The expected oil recovery from this pilot test was 66% of the oil in place at the start of the pilot test.

Field Description

West Hackberry Field is a mature South Louisiana oilfield. It was discovered in 1924. The field has seven productive sands at depths ranging from 3,000 ft down to 12,000 ft. These sand layers are generally correlatable throughout the field. Production comes primarily from the Camerina sands. A type log is provided in Fig. 2.

West Hackberry Field was formed on top of a salt dome and is composed of multitude of fault blocks. The trap for the Oligocene Age Camerina Sands is an erosional unconformity which resulted from the upward movement of the salt. The Camerina Sands were eroded and subsequently overlain by younger Oligocene shales that acted as a seal to trap the oil in the Camerina sands below the unconformity. A structure map is provided in Fig. 3.

A core analysis log for a typical well is provided in Fig. 4. Porosity ranges from 24% to 30%, permeability varies from 300 to 1,000 mD, and the existing residual oil saturation to water is around 26%. In the secondary gas cap zones, the residual oil to gas has been estimated to be as low as 8%. This is another demonstration of the effectiveness of gravity drainage. The oil is a 33° API oil with a viscosity of 0.9 cP at a reservoir temperature of 200° F. The original oil bubblepoint pressure was estimated at 3,295 psi. Other fluid and reservoir properties are listed in Table 1.

The cumulative recovery from this field as of 1/1/93 has been 109 MMBbls oil, 125 BCF of gas and 67 MMBbls of water. The production history is shown in Fig. 5. Amoco is currently producing 1,300 bbl oil, 2 million cubic feet of gas as well as 1,100 bbl water/day from 36 producing wells. The primary production performance of the field has been influenced by an active aquifer located at the bottom of the sand that has displaced the oil uphill over the past 70 years and has kept the oil pressure above its bubblepoint in most fault blocks. However, in some fault blocks there is no aquifer support and depletion has caused formation of gas caps. In such volumetrically depleting fault blocks, historical performance indicates that gravity drainage has recovered 80%-90% of the original oil in place while water-drive reservoirs have recovered 50%-60% of the original oil in place.

Gravity Drainage

At West Hackberry, because of its steeply dipping beds, gravity drainage plays a key role. Gravity drainage has two aspects: First, the displaced oil drains downward at a rate given by Darcy's law.[5] Second, the accumulated oil at the bottom of the pay flows down structure to join the oil bank.[5-8]

Gravity drainage is slow. Generally, vertical drainage rate increases with higher oil permeability and higher density difference between the oil and the injected gas. Hagoort conducted several centrifuge tests to measure the speed of gravity drainage process.[8] He presented his results in terms of dimensionless recovery-dimensionless time curves. These curves may be used to predict the recovery for a specific core by arriving at the equivalent dimensionless parameters for that core. Among the tested cores by Hagoort, the results of the Weeks Island cores were used to obtain a recovery-time curve for West Hackberry. The results are graphed in Fig. 6 as final oil saturation versus time for two different permeabilities. For example, at a pressure of 3500 psi, it will take about 4 years to lower the oil saturation from 0.26 to 0.10 in a 910 mD, 50 ft oil column.

An important consideration in gas injection in dipping reservoirs is the tilt angle at the interface between the gas and oil.[9] For each set of conditions, there exist a critical rate below which the displacement is stable. At this rate, the viscous and gravity forces are balanced. Because of the changing cross-sectional area perpendicular to flow, calculation of the critical rate is not straight forward. A procedure based on a spreadsheet program was developed for calculating the critical rate, the tilt angle and the minimum rate for Fault Blocks 2 and 4 (FB2 and FB4).

Thermal Effects

Under gravity-stabilized displacement, the reaction between air and oil plays a secondary role. However, in the event of heterogeneous flow, consideration should be given to the spontaneous ignition at reservoir conditions. An instrument called the Accelerating Rate Calorimetry (ARC) can be used to obtain a thermal finger print of oil samples.[2] Several ARC tests were run to study the non-isothermal behavior of oil-air mixture at injection conditions. One thermal finger print is provided in Fig. 7 where the rate of heat release (exotherm) is plotted against the test temperature. The first exotherm occurred at around 125° C (257° F). This is about 50° F above the reservoir temperature. Once the ignition occurred, the exotherm lasted until 350° C (662° F). Such a pattern is an indication of a vigorous burning in the reservoir.

To sustain combustion in the reservoir, a minimum air flux is required. Due to the variable cross-sectional area from top to the bottom of West Hackberry, an increasing air flux with time is needed.

Injection Scheme

The current plans call for air injection into two fault blocks: FB2 and FB4 (see Fig. 3). FB2 is a high pressure block with a steeply dipping bed (see Fig. 8). The tertiary reserve in this block is estimated at 1 MMBbls. The attic area in this fault block contains a high oil saturation at zero gas saturation. Air will be injected at a rate of 1.5 MMSCFD into well Watkins No. 18. This well will be completed in both Cam C-1 and Cam C-2,3. The injection rate was selected based on the critical rate for gravity-stabilized displacement. Appendix B describes the sensitivity of displacement to the injection rate. At this rate, the Dietz tilt angle near the producers for FB2 is expected to be 19°.

Well No. 16 will be used as a monitoring well while Well No. 13 will be used as a downdip producer. Once the gas front passes Well No. 13, this well will be shut-in and another downdip well, GLD No. 18, will be opened for production. The gas saturation will be monitored by frequent logging using Pulsed Neutron Capture (PNC) logs. The injection process is schematically illustrated in Fig. 9.

FB4 is a low pressure block with an existing gas cap. A cross-section of this fault block is shown In Fig. 10. The tertiary reserve in this fault block is about 2 MMBbls. In FB4, air will be injected at about 2.5 MMSCFD into both the Cam C-1 and the Cam C-2,3 of Well No. 51. A combination monitor/producing well is planned which will be drilled down the structure within the Camerina C-1 Sand. By running periodic pulsed neutron logs in this well, the advance of the gas cap and the oil rim will be monitored. In addition to monitoring the advance of the oil rim, the rate of growth of the oil rim can also be measured. Here, two producers will be completed in Cam C-1 and two producers will be completed in Cam C-2,3. Again, as the gas front reaches these producers, they will be shut-in and a downstream well will be opened for production. The injector, producers and monitoring wells are schematically shown in Fig. 11.

As an added advantage from the environmental point of view, injection of the produced gases into other low pressure fault blocks in this field is under consideration.

Rock and Fluid Properties

The results of several relative permeability and capillary pressure tests indicated that the Camerina sand has an unusual wettability. The samples appeared to be water wet in the drainage tests. However, during the imbibition tests, considerable negative capillary pressure was required to force the water into the cores indicating a preference to being oil wet. The same difference was observed among the cores taken from below the water-oil contact to those above the oil contact. Later contact angle measurement showed that the water advancing contact angle exceeded 90° after 312 hours with an equilibrium contact angle in the range of 105 to 120°. It was concluded that the Camerina sand has no strong wetting preference for either oil or water but to be moderately oil wet.

Dumoré and Schols[10] concluded that for both capillary pressure and gravity drainage experiments, the presence of connate water in the permeable medium leads to very low residual oil saturation and the final oil saturation was independent of whether or not the oil phase spreads on water in the presence of gas.

There have been numerous gas-oil and water-oil relative permeability and capillary pressure measurements on this rock. These data were used to arrive at average curves that could be used in a numerical simulator. Fig. 12 illustrates the imbibition and drainage water-oil relative permeability curves. Both the log data and the core tests indicated a residual oil saturation to water of about 26%. The irreducible water saturation was estimated to be 20% while the residual oil saturation to gas was assumed to be 5%. Notice that the cross-over saturations do not resemble oil wet characteristics. The average gas-oil relative permeability curves are shown in Fig. 13. For comparison, the West Hawkins[1] and Weeks Island[4] curves also are shown. There is a close agreement between the average curves and Hawkins curves. The available air-oil capillary pressure data were normalized using J-Function and the average curve (shown in Fig. 14) was used in the numerical simulator. For 3-phase relative permeability calculations, the Stone's I with a minimum oil saturation of 5% was used in the simulation.

The fluid phase behavior and the compositional effects play an important role in the DDP with air. In a previous study, it was shown that such behavior can be captured in compositional thermal simulators by using K-values of a select number of lumped hydrocarbon fractions.[3] The same procedure was used to characterize the West Hackberry oil. The fluid properties were taken from a 1953 Core Lab report (see Fig. 15). The oil was divided into 3 pure components and 3 pseudo components, N_2, CO_2, C_1, C_2-C_6, C_7-C_{15} and C_{16}+. Table 2 provides the important input data for the simulation runs.

Procedure for Fieldwide Simulation

Appendix A describes the procedure used to validate the SSI numerical thermal model, THERM, for simulating the gravity drainage process in West Hackberry. The computed oil recovery and the Dietz tilt angle in simple cross-sectional models were compared with the analytical results. The agreement indicated that this model properly simulates the gravity drainage process.

A 34x14x3 rectangular gridblock model (Δx=92.4, Δy=80, Δz=13, 13, 5 from top to bottom respectively) dipping at 30° was used to represent a 1/2 symmetry element of FB2 (see Fig. 16). Because of the unusual shape of FB4, a full field element was selected. The grids were: 32x39x3 (Δx=93.4, Δy=78.1, Δz=16, 16, 5 from top to bottom respectively) and the dip was 35°. Appendix B discusses the impact of the z-direction gridblocks on this process. The aquifer was modeled at the bottom of the structure by using super gridblocks at the bottom row of gridblocks. The strength of the aquifer was arrived at by matching the historical oil recovery and the field WOR. The injection rate into Cam C1 was obtained by proportioning the total assigned injection rate into each fault block by the KH ratio of Cam C1 over the total KH. The procedures were shut in at the time of oxygen breakthrough.

Since FB4 had been depleted to a pressure below the bubblepoint pressure, a gas cap had been formed up structure. Instead of history matching its primary production, an existing saturation profile was imposed on FB4 as shown in Fig. 16. The oil rim represents the drained oil from the gas cap.

Model Results

The performance curves (oil recovery-hydrocarbon volume injected = HCPVI) under the proposed injection rates for both fault blocks are shown in Fig. 17. The HCPVI in FB2 and FB4 are at 4,000 and 2,000 psi, respectively. The delay in the oil production in FB4 is due to the presence of gas cap and the longer distance between the injector and the producers in this fault block. Since the injected and the combustion gases strip the light hydrocarbons, the produced fluids had to be flashed separately to arrive at the NGL content (mostly C_2-C_6 hydrocarbons) of the effluent gas (the numerical thermal model does not have a surface flash option). Fig. 18 shows the ratio of the produced NGL to the total produced oil. These results were scaled up to the full sand face injection rate. The field oil and NGL production rates are shown in Fig. 19. Notice that production is forecasted until the year 2008. No production was allowed for 3 years to lower the production costs. The oil production from FB4 came on stream in the fourth year. The maximum production was predicted to occur in the year 2001. The average reservoir pressure for both fault blocks are shown in Fig. 20. The rise in the reservoir pressure helped push the water downstream. The oscillation in the later years is due to shutting in some of the producers and opening the wells down structure. The effect of the DDP is demonstrated in saturation contours after 7 years of injection (Fig. 21). The temperature profiles are shown in Fig. 22 for both fault blocks. The thermal front appears to be far from the producers even after 7 years of injection.

Sensitivity Runs

The effect of vertical permeability variation was investigated by changing the layer permeability from top to bottom. The average permeability was kept the same. The results indicated that higher permeability at the bottom and lower permeability at the top tend to improve the performance by delaying the gas breakthrough. A performance deterioration was observed when the permeability trend was reversed. However, the difference in these cases was not significant. Ypma[11] observed that discontinuous shale layers do not adversely affect the recovery efficiency of immiscible gas injection. By reducing the effective vertical drainage distance, they might even slightly enhance the recovery.

The effect of injecting N_2 instead of air was investigated in a separate run. The results confirmed an observation made in a previous paper,[2] i.e., the N_2 and air response are virtually the same until much later when the thermal oil bank arrives at the producers. Other injection schemes such as cyclic injection-production and an injection period followed by a waiting period before the start of production also were modeled. These injection schemes generally had mixed oil response due to their dependency on an optimum timing.

Field Facility Design

Like many other improved recovery techniques, the safety aspects have to be addressed prior to project startup. For example, to prevent explosions in the air injection lines, synthetic lubricants will be used. To prevent explosions in wellbores due to backflow, a water purge system will be installed that will be operational upon interruption of air flow. Although our simulation results indicated that oxygen breakthrough in the producers will not occur until late in the project life, the composition of the produced gas will be monitored. Additional concerns include possible behind pipe communication with other reservoirs and the geologic complexity of salt dome reservoirs.[12]

Gas coning into the oil column and movement of the oil column into the aquifer are other concerns. Both the producing and monitoring wells will be logged to detect the movement of gas-oil interface periodically. Gas lifting is used to aid the oil production in this field. Although a single gas lift network is currently used for this purpose, it is planned to use a separate gas lift system once the produced gas stream is contaminated by the combustion gases. Also, although the NGL production is significant, it will not be recovered due to the cost of installation of an NGL plant. The economics of NGL recovery will be reevaluated during the course of the project.

Economics

The calculated air-oil ratios (AOR) are shown in Fig. 23. The cumulative AOR was below 10 MSCF/STB for the most part, indicating an efficient process.

Over the seven years of the DOE contract, the capital expenditure will be around $6 MM and the operating costs are estimated around $14 MM. The project economics indicate that even without DOE funding, the project should be profitable if the project performs as predicted.

CONCLUSIONS

- The West Hackberry project is the creation of a new EOR process which combines the double displacement process with air injection.
- The proposed injection rate of 4 MMSCFD in this field should provide a gravity stabilized displacement in this field.
- Experimental results indicate that combustion will occur at reservoir conditions. However, the hot regions should be limited to the upper parts of the fault blocks and away from the producers during the injection period studied. This project is designed on an environmentally sound basis.
- Compositional effects play an important role in the stabilization of the gas displacement front.
- Based on the advantages of air injection, this process might have worldwide application.

REFERENCES

1. Carlson, L. O.: "Performance of Hawkins Field Unit Under Gas Drive Pressure Maintenance Operations and Development of an Enhanced Oil Recovery Project," SPE/DOE 17324 paper presented at the 1988 SPE/DOE Meeting held in Tulsa, OK, April 17-20.
2. Yannimaras, D. V., A. H. Sufi and M. R. Fassihi, M: "The Case for Air Injection into Deep Light Oil Reservoirs," Paper presented at the 5th European Symp. on IOP, held in Stavanger, Norway, May 21-23, 1991, pp. 55-63.

3. Fassihi, M. R.: "Improved Phase Behavior representation for Simulation of Thermal Recovery of Light Oils," SPE 24034 paper presented at the 1992 California Regional Meeting held in Bakersfield, CA, March 30- April 1.
4. Johnston, J. R.: "Weeks Island Gravity Stable CO_2 Pilot," SPE/DOE 17351 paper presented at the 1988 SPE/DOE Meeting held in Tulsa, OK, Apr. 17-20.
5. Cardwell, W. T., Jr., and R. L. Parsons: "Gravity Drainage Theory," *Trans. AIME*, v. 179, 1949, pp. 199-215.
6. Richardson, J. G. and R. J. Blackwell: "Use of Simple Mathematical Models for Predicting Reservoir Behavior," *J.P.T.*, September 1971, pp. 1145-1154.
7. Dykstra, H.: "The Prediction of Oil Recovery by Gravity Drainage," *J.P.T.*, May 1978, pp. 818-830.
8. Hagoort, J.: "Oil recovery by Gravity Drainage," *S.P.E.J.*, June 1980, pp. 139-150.
9. Hawthrone, R. G.: "Two-Phase Flow in Two-Dimensional Systems - Effects of Rate, Viscosity, and Density on Fluid Displacement in Porous Media," *Trans. AIME*, v. 219, 1960, pp. 81-87.
10. Dumoré, J. M., and R. S. Schols: "Drainage Capillary-Pressure Functions and the Influence of Connate Water," *S.P.E.J.*, October 1974, pp. 437-444.
11. Ypma, J. G. J.: "Analytical and Numerical Modeling of Immiscible Gravity-Stable Gas Injection into Stratified Reservoirs," *S.P.E.J.* (August 1985) pp. 554-564.
12. Bleakley, W. B.: "Chevron's attic-oil recovery in south Louisiana looks good," *Oil & Gas J.*, Nov. 13, 1967, pp. 132-134.

Nomenclature

a_r	=	air requirement, SCF/ft^3 of rock
C_f	=	Fuel laydown, lb/ft^3
$g.b.t.$	=	gas breakthrough
h	=	net pay, ft
HCPVI	=	Hydrocarbon Pore Volumes Injected
k	=	absolute permeability, Da
k_{rg}	=	gas relative permeability, fraction
k_{ro}	=	oil relative permeability, fraction
Nx, Ny, Nz	=	No. of grid blocks in x, y, z directions respectively
q	=	Injection rate, MMSCFD
q_{min}	=	Minimum injection rate to sustain combustion, MMSCFD
u	=	injection flux, ft/D
u_c	=	critical flux, ft/D (see Eq. A.2)
V_f	=	combustion front velocity, ft/D
α	=	dip angle, degrees
β	=	tilt angle, degrees (see Eq. A.1)
$\Delta\rho$	=	density difference (ρ_o - ρ_g), lb/ft^3
Δx, Δy, Δz		grid block thickness in x, y, z directions respectively, ft
μ_g	=	gas viscosity, cP
μ_o	=	oil viscosity, cP

APPENDIX A
Modeling the Gravity Drainage Process

The effect of gridblock size on both oil recovery and the tilt angle in the gravity drainage process was investigated by running several cross-sectional dipping cases using the data from the West Hawkins field (see Ref. 6). The tilt angle is the stabilized tilt angle at the gas-oil interface as predicted by the equation proposed by Dietz,[9] i.e.,

$$\tan\beta = (1 - \frac{u}{u_c})\tan\alpha \qquad \text{(A-1)}$$

where u_c is the critical flux for gravity stabilized displacement and is given by:

$$u_c = \frac{0.044 kh\Delta\rho \sin\alpha}{k_{ro}/\mu_o - k_{rg}/\mu_g} \qquad \text{(A-2)}$$

Table A1 provides the results of this study. In Runs 1A and 2A, the effect of mobile water saturation was studied. At both irreducible water saturation (.08) and maximum water saturation (.774), there was a good agreement between the theoretical and calculate tilt angle (3.4°). The oil recovery at gas breakthrough was different because of different volumes of oil in place. The displacement of water by oil did not affect the gas-oil displacement. Fig. A1 shows the gas saturation profile for these two runs at the same HCPVI. The low gas saturation in the bottom layer in both cases is due to the oil buildup by drainage. In Run 3A, the injection rate was halved. The oil recovery was higher in this run due to a lower injection flux and the agreement in the calculated β was good.

In Runs 4A through 7A the number of gridblocks in the vertical direction were decreased from 10 to 3. Notice that the oil recovery at gas breakthrough matched the oil recovery in the base Run 3A only when the bottom layer thickness was comparable with that in Run 3A. This indicates that as long as the bottom layer is thin enough to allow for the flow of drained oil down the structure, the number of gridblocks in the vertical direction do not have a significant impact on the oil recovery. A similar result was obtained by Ypma[11] who concluded that a fine grid is needed at the bottom of the model to avoid oil from after-drainage being held up in the lowest layer. In all field simulation runs, the bottom layer thickness was kept at 5 ft while thicker gridblocks were used in the upper layers. In runs with Nz = 3, the tilt angle was not calculated.

APPENDIX B
Sensitivity Study of the Injection Rate

The effect of the injection rate on oil displacement at West Hackberry was studied at two pressures, 1,200 and 4,200 psi. A cross-sectional grid 36x10 ($\Delta x = 175$, $\Delta z = 4.3$ ft) with a dip angle of 35° was used. The injection-withdrawal ratio was maintained at 1 in these runs. The results are shown in Table B1. In this table, q_{min} is the minimum injection rate to sustain the combustion front and is calculated from:

$$q_{\min} = V_{f\min} a_r \qquad \text{(B-1)}$$

V_{fmin} is the minimum front velocity (0.125 ft/D) and a_r is the air required to raise the temperature to 600° F (176 SCF/ft^3) (see below for further discussion).

The calculated tilt angle and the burning front velocity, V_f, are also provided in the table. Higher injection rate increased the front velocity at the expense of a highly unstabilized gas-oil interface ($\beta = 0$) (compare Runs 2B and 1B). However, at higher pressures, higher injection rate can be tolerated because of the effect of pressure on the injected flux (compare Runs 2B and 4B).

The effect of dissolution of the injected gas in the oil phase and its impact on the critical rate was studied in Runs 5B and 6B. To allow for a higher mass transfer between the generated flue gas and the oil phase, only the heavy fraction of the oil (C_{16+}, m=6.4) was initially present in these runs. The higher oil viscosity in Run 5B made the low pressure, low rate case unstable. The higher pressure run (Run 6B) was initially unstable and gas overran the liquid as shown in the top cross section in Fig. B1. However, later dissolution of the flue gas in the oil phase created a transition zone with a lower oil viscosity that allowed stabilization to occur. The disappearance of the gas phase and stabilization of the gas-oil interface is clearly seen in the contour plots in Fig. B1. The effective oil phase viscosity was 1.4 in this zone.

Table 1: Comparison of Reservoir and Fluid Properties in Three Projects

	W. Hackberry Cam C1-C3	Hawkins Dexter sand	Weeks Island S RB
Porosity, %	27.6-23.9	27	26
Permeability, md	300-1000	3400	1200
Swi, %	19-23	13	10
Sorw, %	26	35	22
Sorg, %	8 (est.)	12	1.9
Reservoir Temperature, F	205-195	168	225
Bed Dip, degrees	23-35	8	26
Pay Thickness, ft	31-30	230	186
API Gravity	33	25	32.7
Viscosity	0.9	3.7	0.45
Bubble Point, Pressure, psi	3295	1985	6013
GOR, SCF/STB	500	900	1386
Oil FVF at Pbp	1.285	1.225	1.62
Waterdrive Recovery, %OOIP	60	60	--
Gravity Drainage Recovery, %OOIP	90 (est.)	85	95

Table 2: Reservoir and Fluid Properties Used in the Simulation of West Hackberry

Porosity	0.276	
Permeability, md	300	
Kv/Kh	0.1	
S_{wi}	0.2	
S_{org}	0.05	
S_{orw}	0.26	
Oil Composition		
C_1	0.467	
C_2-C_6	0.0657	
C_7-C_{15}	0.2499	
C_{16}+	0.1983	
N_2	0.0138	
CO_2	0.0053	
	FB2	FB4
Cam C_1 Pay, ft	31	43
Cam C_2, C_3, Pay, ft	54	78
Temperature, $^\circ$F	208	200

Table A1: Effect of Gridblock Size on West Hawkins Performance Prediction

Run	Nx	Nz	Δz	S_{wi}	u/u_c	β (theor.)	β (calc.)	Oil Rec. (@ g.b.t.)
1A	24	10	4.9	.08	.435	3.4	3.2	0.77
2A	24	10	4.9	.774	.435	3.4	3.18	0.076
3A	48	10	4.9	.08	.217	4.7	4.57	0.851
4A	24	5	9.8	.08	.217	--	--	0.81
5A	24	5	*	.08	.217	--	--	0.833
6A	24	3	16.33	.08	.217	--	--	0.771
7A	24	3	*	.08	.217	--	--	0.83

*The top 4 layers at Δz=11.025 and the bottom layer at Δz=4.9
**The top 2 layers at Δz=22.05 and the bottom layer at Δz=4.9

Table B1: Effect of Pressure and Air Injection Rate on West Hackberry Performance

Run No.	Pressure psi	Inj. Rate MMSCFD	q/q_{min}	u/u_c	β degrees	Vf ft/D
1B	1200	1	.5	.84	4.6	.087
2B	1200	3	1.5	2.5	0	.131
3B	4200	1	.5	.15	13	.08
4B	4200	5	2.5	.73	9.3	.44
5B	1200	1	.5	2.85	0	.05
6B	4200	3	1.5	3.3	7.8	.21

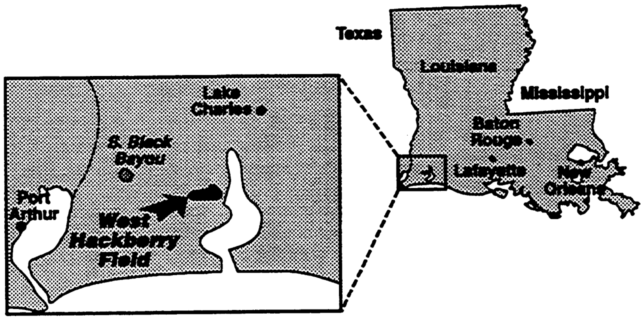


Figure 1: Amoco Production Company, West Hackberry Field

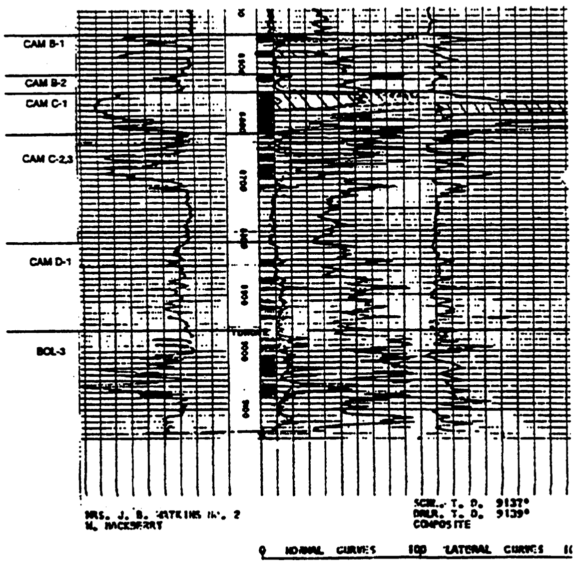


Figure 2: Type Log - Well Watkins No. 2

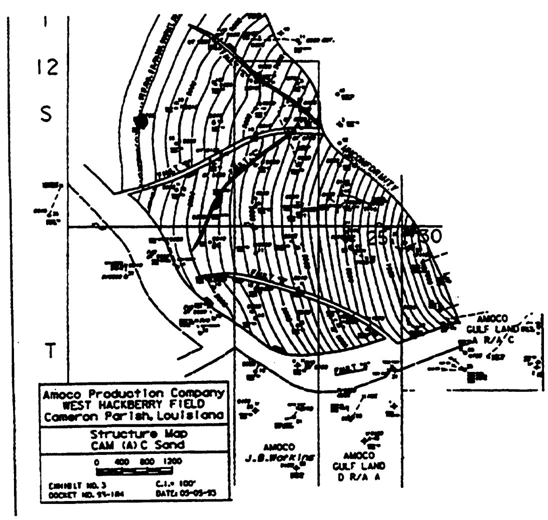


Figure 3: Structure Map - Top of Cam C1 Sand

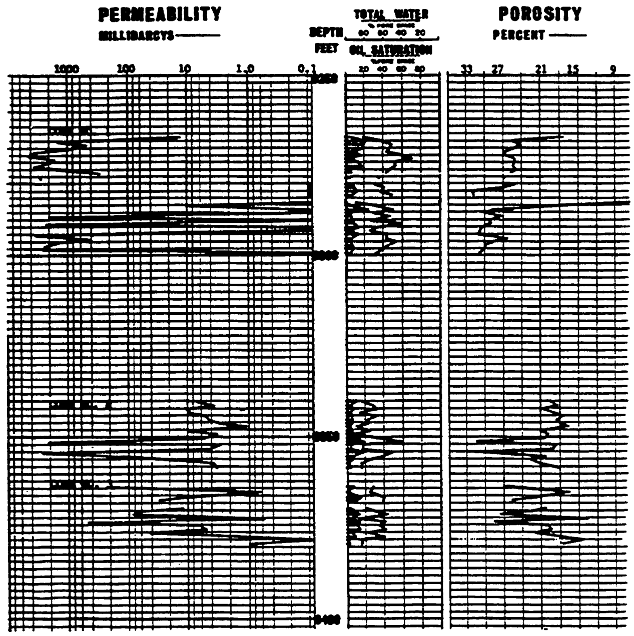


Figure 4: Core Log - Well 173

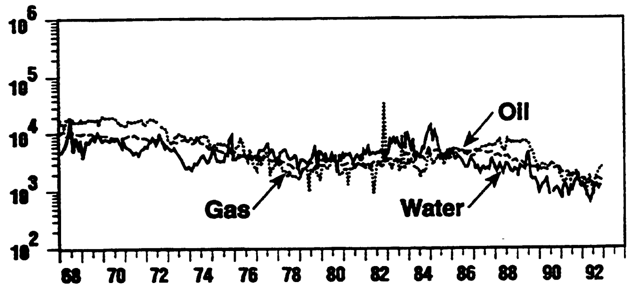


Figure 5: Production History for West Hackberry Field, Amoco Interest Wells - 1968 to Present

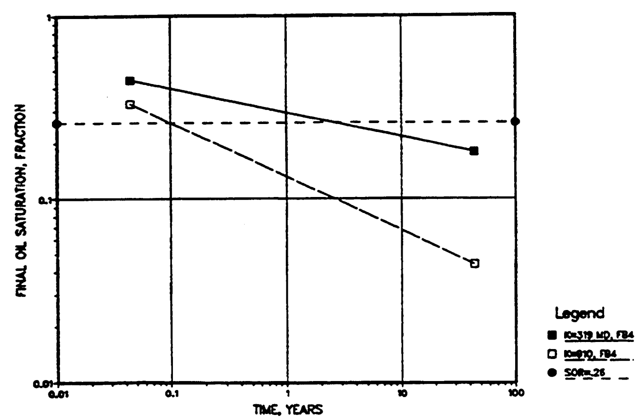


Figure 6: The Estimated Final Oil Saturation for West Hackberry Under Gravity Drainage Based on Hagort Data on Weeks Island (L=50 ft)

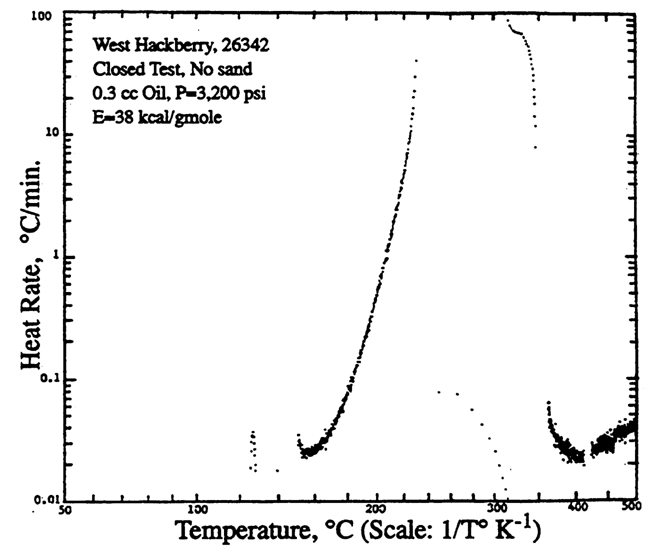


Figure 7: Self Heat Rate vs. Temperature Plot

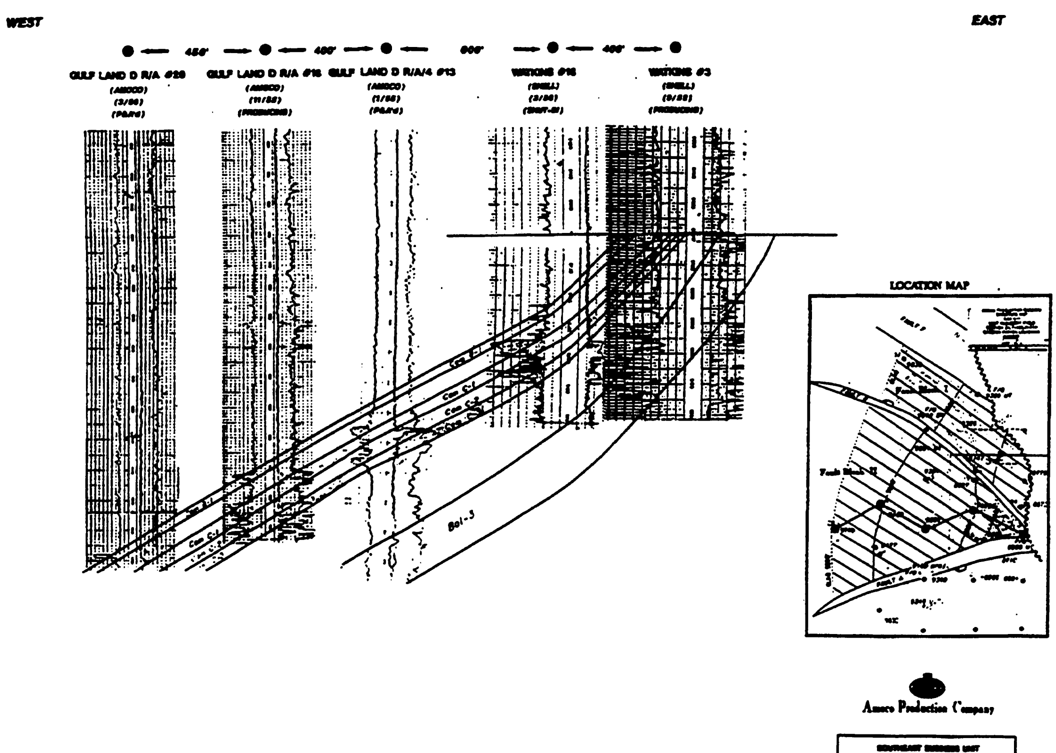


Figure 8: Fault Block 2

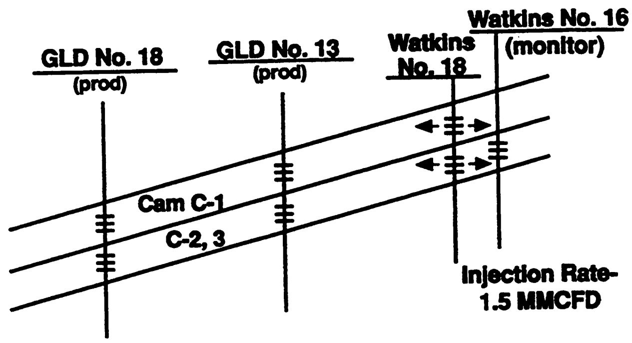


Figure 9: Fault Block 2, High Pressure Case

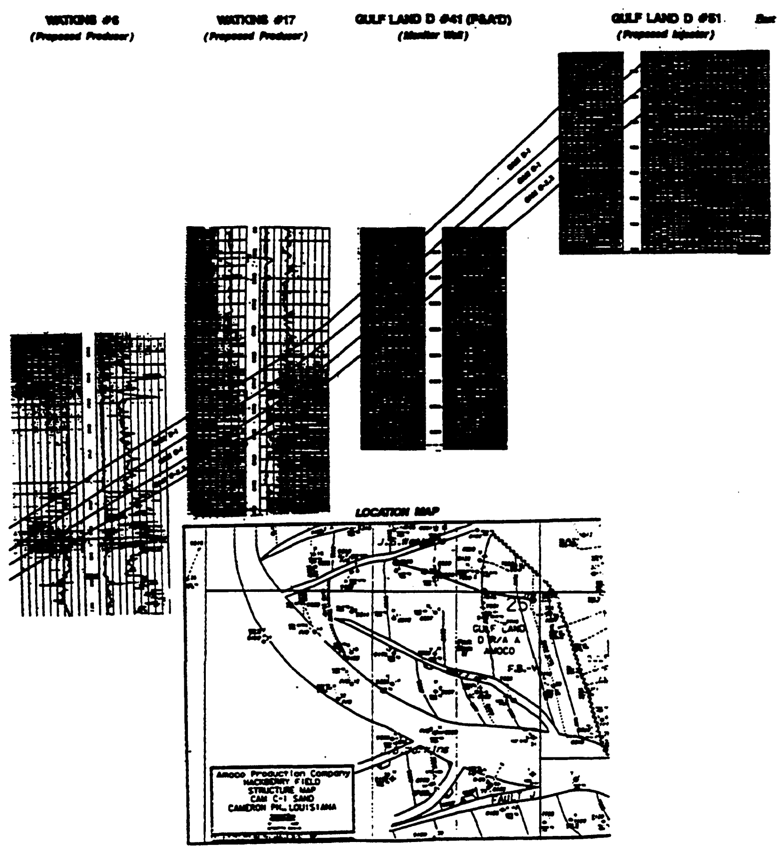


Figure 10: Fault Block 4

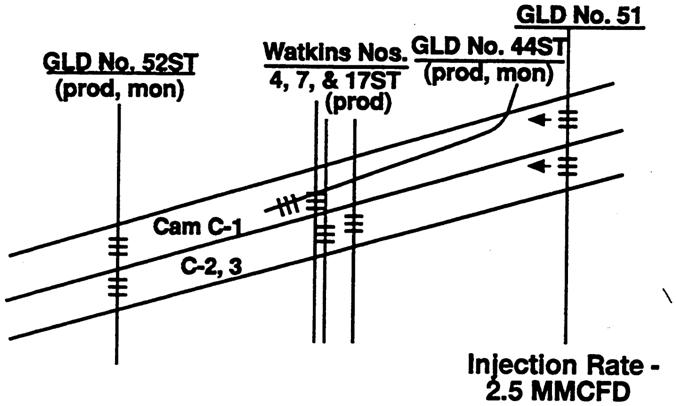


Figure 11: Fault Block 4, Low Pressure Case

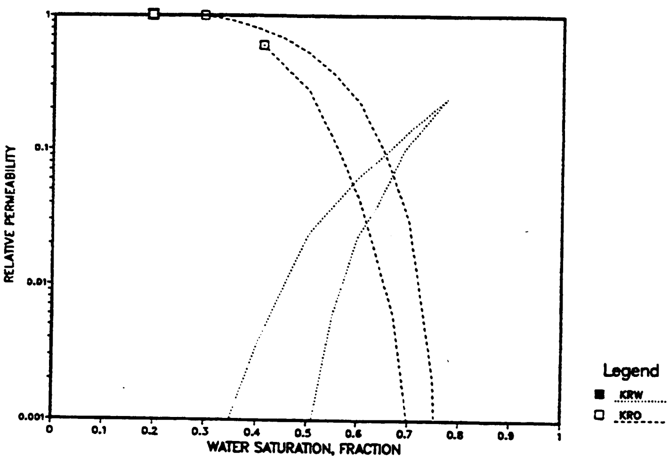


Figure 12: Steady State Water-Oil Relative Permeability Curves, GLD 87, Camerina, 11531 ft, ϕ =.209, k_o=145 md

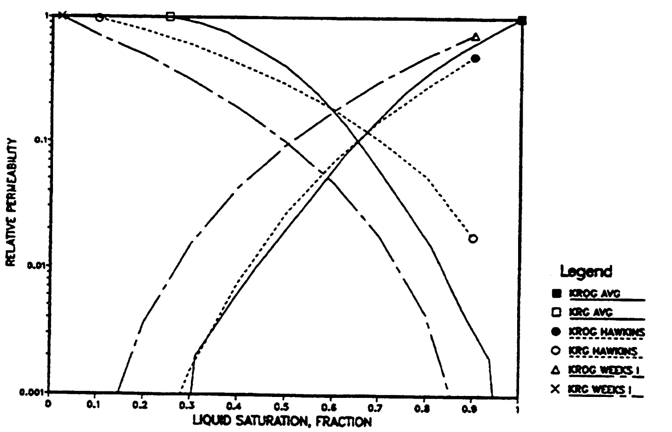


Figure 13: Gas-Liquid Relative Permeability Curves

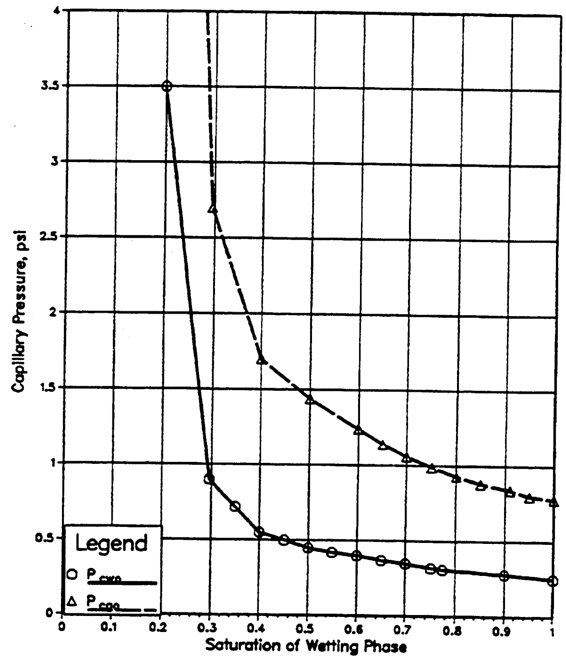


Figure 14: West Hackberry Capillary Pressure Curves

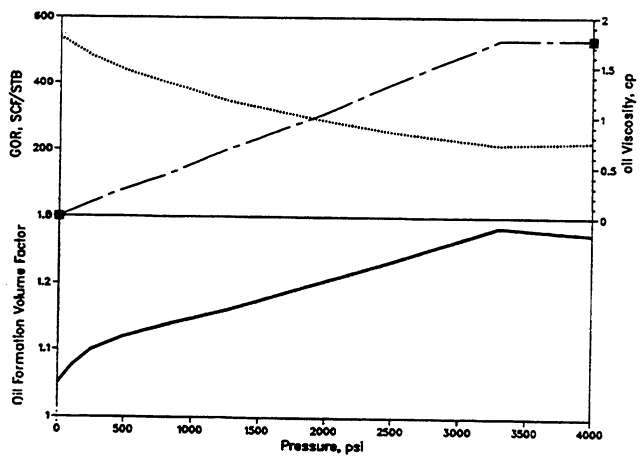


Figure 15: Oil Properties vs. Pressure, West Hackberry, GLD9

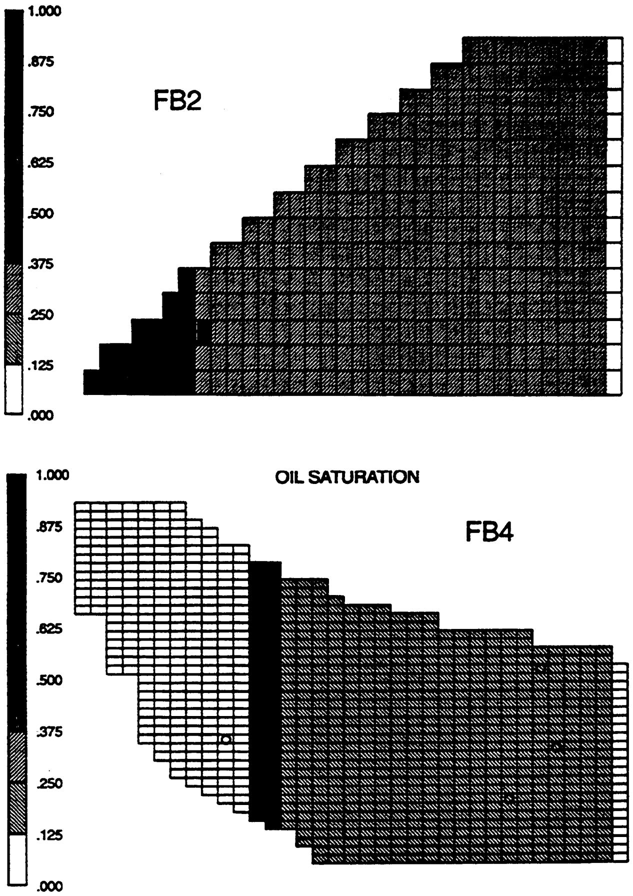


Figure 16: Oil Saturation Contours at the Start of Air Injection

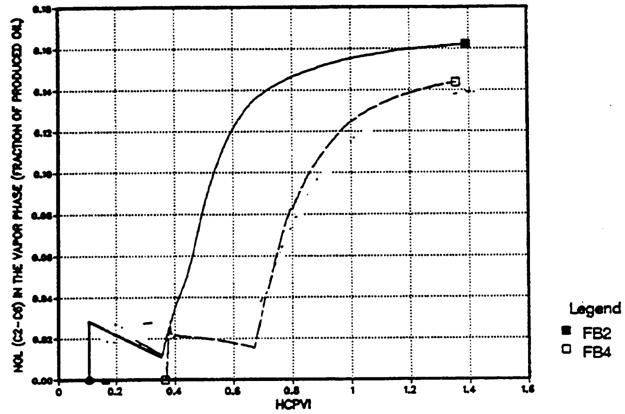


Figure 18: Fraction of the Produced Oil as NGL in the Vapor Phase

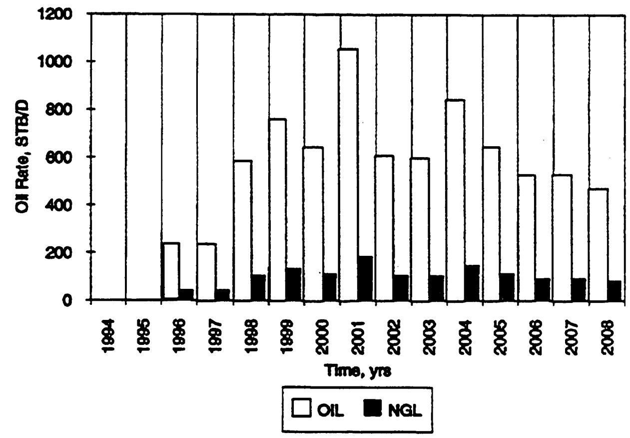


Figure 19: Predicted Oil and NGL Production Rates

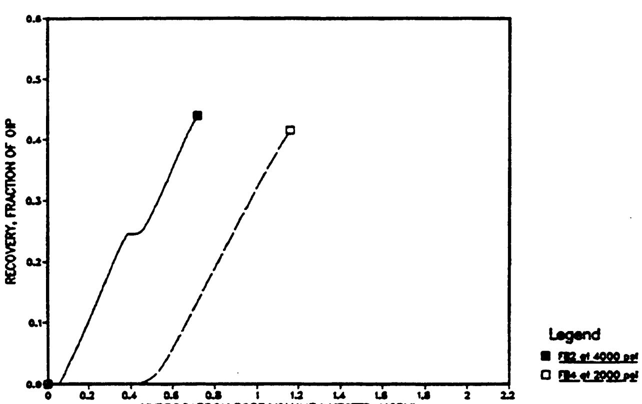


Figure 17: Estimated Oil Recovery for West Hackberry Air Injection Project, Fault Block 2 and 4, Cam C1 Only

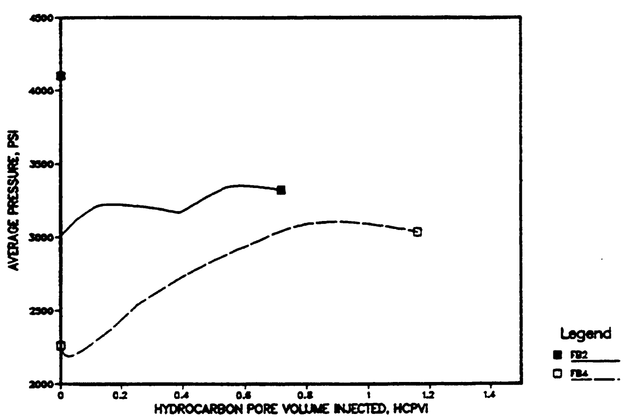


Figure 20: Average pressures in Fault Blocks 2 and 4 (Cam C1 Only)

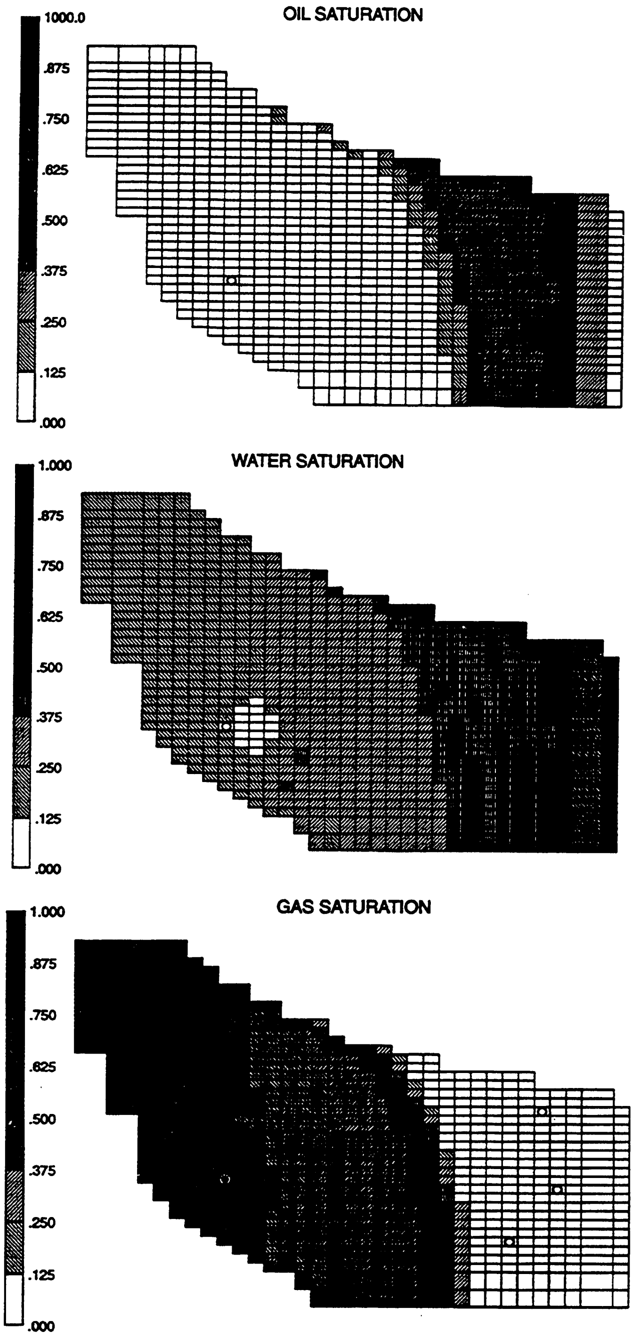


Figure 21: Saturation Contours after 7 years of Air Injection, FB4

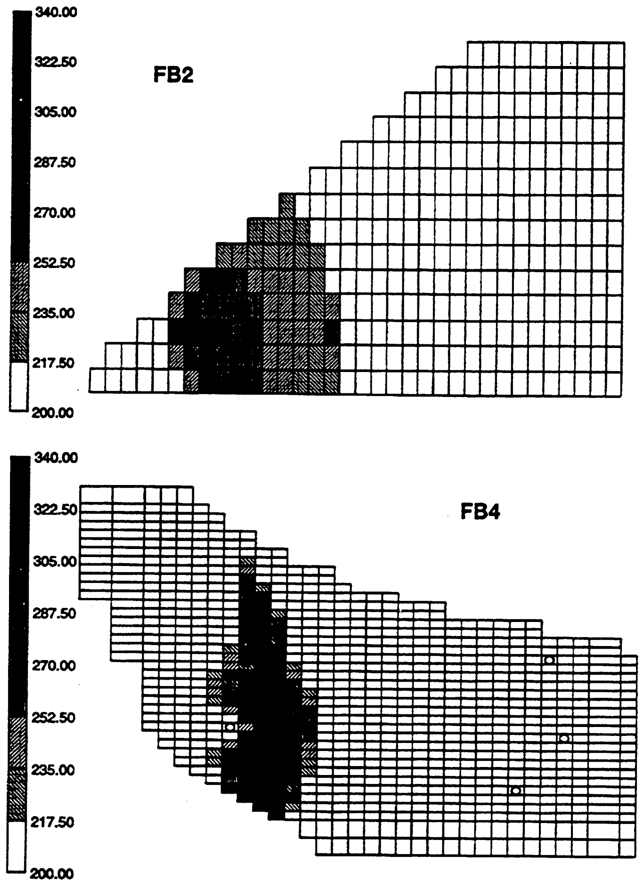


Figure 22: Temperature Profiles after 7 years of Injection

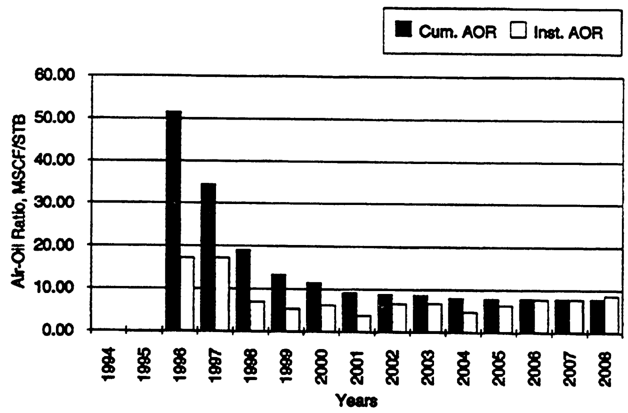


Figure 23: Calculated Air-Oil Ratio

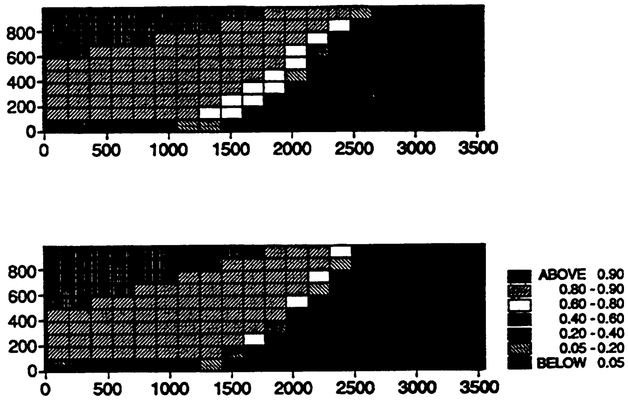


Figure A1: Effect of Initial Water Saturation on Gas Saturation Profiles (S_{wi} = .08 top, S_{wi} = .774 bottom, HCPVI = .511)

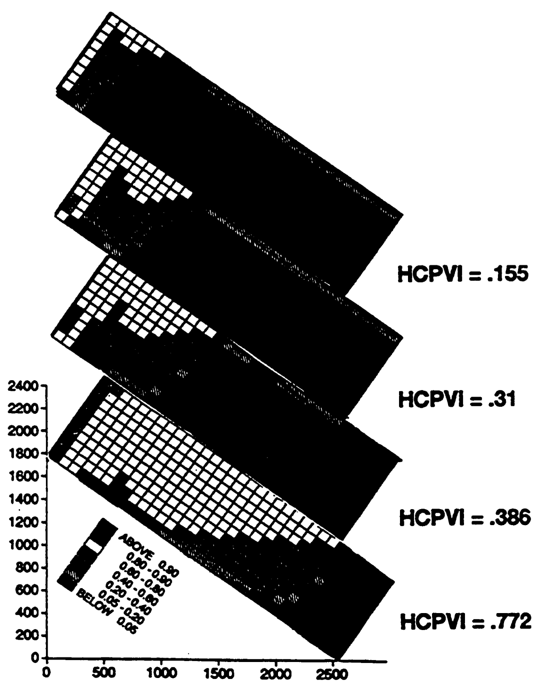


Figure B1: Gas Saturation Contours at Different Times in Run 6B (time increases from top to bottom)

No. ISC 11

DOE/NIPER

Improved Sweep Efficiency Through the Application of Horizontal Well Technology in a Mature Combustion EOR Project: Battrum Field, Saskatchewan, Canada

by B. G. Ames, R. E. Grams and F. N. Pebdani, Mobil Oil Canada, Calgary, Alberta, Canada

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

In-situ combustion has been employed in the Battrum field since 1964. Although the field has responded favorably to combustion, efficiency of the horizontal displacement process appears to be poor in some areas of the field. Injected air and combustion gases accumulate at the top of the reservoir, and injected water moves into a zone of relatively high mobile water saturation, occurring at the base of the reservoir. Rapid breakthrough of the injected fluids increases operating costs due to high gas-oil ratios. Placement of horizontal wells below the combustion gas cap, and conversion to a vertical displacement process is expected to increase oil rate, improve oil recovery, and reduce operating costs.

Mobil and its partners have drilled two horizontal wells in the field. Both wells produce at oil rates considerably higher than vertical wells, at very low gas-oil ratios, and minimal drawdown. The first well produces at an oil rate ten times greater than the average rate achieved in vertical wells. Oil rates are lower in the second well due to high water cut. The zone of high mobile water saturation, situated at the base of the reservoir appears to strongly influence production in this well. Simulation and remedial work have been initiated in an attempt to increase oil rate in this well, while minimizing water cut and gas-oil ratios.

INTRODUCTION

The Battrum Field, located approximately 50 km northwest of Swift Current, Saskatchewan (Figure 1), has been producing since its discovery in 1955. Medium gravity oil is produced from shallow unconsolidated sands of the Jurassic Roseray Formation. Although these reservoir sands are very similar to other Roseray reservoirs of Southwestern Saskatchewan, oil produced from this field is somewhat more viscous than that found in other Roseray pools.

Mobil Oil Canada operates three of the five units in the field (Figure 2) using an in-situ combustion process, which has been in operation for almost 30 years. The process of combustion has not been clearly understood due principally to (1) the size and complexity of the operation, and (2) a poor understanding of reservoir geometry and corresponding fluid distribution. Although the process was previously envisioned to involve piston-like displacement, recent studies indicate that frontal displacement is not the dominant displacement mechanism in much of the field. Gravity effects appear to dominate fluid distribution within the reservoir. Injected gases override the oil column, creating an immiscible secondary gas cap at the top of the reservoir, while water underrides the oil column.

Based upon the current understanding of fluid distribution, a displacement process involving the use of horizontal wells has been identified. The potential for increased oil recovery through vertical gas displacement of heated oil toward horizontal producers situated near the base of the lower most sand in the reservoir (Lower Roseray) is being evaluated. Mobil and its partners have drilled two horizontal wells in the field and are currently evaluating the feasibility of such a process at Battrum.

References, tables and illustrations at end of paper.

HISTORY

The Battrum Field was initially developed on 16 hectare spacing and operated under primary recovery until the mid-1960's when it was determined that ultimate recovery would be low, due to the viscous nature of the oil and low reservoir pressure. An evaluation of the relative merits of in-situ combustion and waterflood recovery techniques indicated that in-situ combustion would yield more attractive recoveries and economics than would waterflood. Consequently, a dry combustion recovery process, involving continuous injection of air, was initiated in Unit 2. This project, initiated in the extreme northwest corner of the field, resulted in immediate oil rate improvements.

Based upon good results in Unit 2, in-situ combustion was expanded to Units 1 and 3, and much of the field was subsequently infill drilled to 8 hectare spacing. Approximately 300 vertical wells have been drilled. There are currently 24 air-water injection wells and 150 producing wells within the Mobil operated Units.

GEOLOGY

The main hydrocarbon producing horizons of the Battrum Field are quartzose shoreface sandstones of the Roseray Formation, a member of the Upper Jurassic Vanguard Group.[1] The Roseray lithosome defines an offlapping parasequence set deposited in response to southeasterly progradation across the Swift Current Platform during a period of relative sea-level rise. Correlation of marine shales deposited at the marine flooding surfaces between these parasequences indicates that, within the Battrum Field, the Roseray sands include four of the parasequences within this parasequence set. The lower two parasequences are referred to as the Lower Roseray member, and the upper two parasequences are referred to as the Upper Roseray member (Figure 3). These members, previously referred to as the Roseray and Battrum sands, are separated by a prominent argillaceous marine shale which acts as an effective barrier to vertical permeability throughout the field.

The Lower Roseray sands are thick and provide the best quality reservoir in the field (Figure 4). These sands are thickest in the west portion of the field where they attain a maximum thickness of 16 metres. The sands display excellent vertical permeability. To the east, reservoir quality deteriorates rapidly, and a marine shale develops between the lower two parasequences, creating a barrier to vertical permeability in the eastern portions of the field. The deterioration in reservoir quality is reflected on the map of hydrocarbon porosity thickness (Figure 5).

The Upper Roseray member is typically a poorer quality reservoir than the Lower Roseray. It is usually more clay rich, contains more sand-shale interbeds, is of less uniform reservoir quality, and thinner than the Lower Roseray. Individual sands in this unit range in thickness from 2 to 5 metres, and sometimes stack to attain a thickness of 10 metres. Besides containing numerous shale interbeds the Upper Roseray has been severely dissected by erosion on the low relief pre-Success unconformity. The dissected nature of this unit is illustrated in Figure 6.

Hydrocarbon trapping occurred due to pre-Mannville uplift and the creation of a high relief unconformity along the updip, western and northern edges of the field. Subsequent deposition of argillaceous Cantuar valley fill created an updip seal against the reservoir. This unconformity, the deterioration in reservoir quality to the east, and the presence of the field oil-water contact to the southeast define the limits of the field.

The medium gravity crude of this field (18° API), which at original reservoir conditions of 46° C and 8,500 kPa has a viscosity of 70 cP, is reservoired within very fine to fine grained, moderately to well sorted and poorly consolidated sands. Reservoir quality is excellent with porosities and permeabilities ranging between 25 to 35%, and 0.5 to 10 darcys, respectively (Figures 7 and 8).

Reservoir quality varies as a function of detrital and authigenic clay content. Although slightly coarser grained, the Upper Roseray generally exhibits poorer reservoir quality than the Lower Roseray, due to a greater abundance of authigenic kaolinite clay. The Lower Roseray has a distinct cleaning upward nature as illustrated by an increase in formation resistivity towards the top of the reservoir (Figure 4). This coincides with a downward increase in clay content and a corresponding increase in irreducible water saturation.

Besides the increase in irreducible water saturation toward the base of the Lower Roseray there exists, everywhere except at the structurally highest portions of the field, a zone of highly mobile water at the base of this sand. Drillstem tests run early in the life of the field demonstrated the presence of an inclined transition zone at, and sub-parallel to the base of the reservoir. This zone of high mobile water saturation thickens downdip and eventually merges with the field oil-water contact.

PRODUCTION HISTORY (Lower Roseray)

During much of the primary production period the Lower Roseray produced at a rate of approximately 400 m^3/d. Average initial oil rate was 15 m^3/d per well, but oil rate and gross fluid rate declined as reservoir pressure fell. Reservoir pressure fell most rapidly in the northwest portion of the field, where within three years it had fallen from initial reservoir pressure of 8,500 kPa to near bubble point pressure of 1,400 kPa. This decline in reservoir pressure was most pronounced where the Lower Roseray was not underlain by mobile water, such as the structurally high northwest corner of the field. It is also evident that the pressure gradient from the southern to the northwestern portions in the reservoir, corresponds to an updip decrease in primary water cut. Initial water cut increased in a regular fashion from values of 5% in an updip position, and from values of 90% in a downdip position, closer to the field oil-water contact.

This trend in water cut, along with the corresponding trend in reservoir pressure, is believed to be related to the presence of mobile water at the base of the sand. Given the high water-oil mobility ratios exhibited in this field, influx of water from the aquifer and water injection wells through the mobile water zone may be a more efficient voidage replacement mechanism than horizontal displacement of oil through the reservoir. Consequently, the mobile water zone dominates pressure maintenance and voidage replacement in those areas which it underlays. In areas, such as the northwest portion of the field, where the mobile water zone was not present, or where relative permeability to water was low, horizontal displacement of oil is believed to have been the dominate voidage replacement mechanism.

Accordingly, areas underlain by the mobile water zone received a greater degree of pressure support from the aquifer, yet at the same time had higher water production due to the proximity of mobile water. Water cut increased rapidly as water coned from the mobile water zone situated at the base of the sand. Attempts were made to minimize water cut by perforating the producing wells near the top of the Lower Roseray.

As reservoir pressure dropped to the near bubble point pressure in the northwest corner of the field it became apparent that pressure maintenance would be required. Waterflood and combustion processes were evaluated. Waterflood was dismissed in favour of the higher recoveries and better economics predicted for a combustion process. At that time, it was believed that waterflood recovery efficiency would be low due to immediate channeling of injection water to the underlying mobile water zone.

Since the combustion process was first initiated in 1964, it has been operated in two forms—dry and wet combustion. The dry combustion process involves the injection of air; wet combustion on the other hand involves alternating injection of air and water, at a single injector. The field operated under dry combustion from 1964 until the mid-1970's when conversion to wet combustion occurred.

The initiation of dry combustion in the northwest corner of the field, resulted in the immediate doubling of oil rates existing at that time. These rates were maintained near early primary rates, of approximately 8 m^3/d/well for a period of nine years. Such rate increases are impressive, as are residual oil saturations documented in core samples recovered from zones swept by the combustion front. Core samples from the gas swept combustion zone indicate residual oil saturations of 0.7 percent.

Although these increases in oil rate and recovery are impressive, they have not been achieved without cost. The initiation of the combustion process resulted in a significant increase in operating cost. The increased operating cost occurred due to operational problems associated with the production and treating of oil produced at high combustion gas-oil ratios. These problems include pump failures, corrosion, sand production, and the treating of produced fluids which include very stable oil-water emulsions.

One of the main factors contributing to high gas-oil ratios and the corresponding increase in operating cost is the unanticipated creation of a secondary combustion gas cap in the reservoir. Due to the density contrast between oil and gas, and the absence of vertical permeability barriers within the Lower Roseray, injected gases override of the oil column and migrate to the top of the reservoir, where they accumulate to form a secondary gas cap. The existence of this one to three metre gas cap at the top of the Lower Roseray reservoir is well documented across much of the field by recent wireline logging using neutron logs (Figure 9). The position of this gas cap greatly exacerbates operational problems because its position coincides with the completed interval in producing wells.

Besides creating operational problems, gas override and immediate channeling of injected air from injector to producer results in poor injected fluid conformance and inefficient pressure maintenance from air injection alone. The combustion process also creates stable and highly viscous oil-water emulsions, which besides reducing pump efficiency, are believed to cause inflow reductions at some wells. The creation of these emulsions is suspected to be due to either high gas velocities in the formation or at the sandface in the producing well, or due to low temperature oxidation, or a combination of the preceding.

Injection gas override and core data also suggest that combustion is occurring within a relatively thin combustion zone at the top of the Lower Roseray reservoir. Although a thinner burn zone makes the recovery scheme more economical due to reduced air requirements, the burn zone could become too thin to thermally affect the underlying pay. This would necessitate a higher density of burns to maximize recovery.

In the northwest portion of the field, conversion to wet combustion resulted in a further doubling of oil rates existing at that time. This positive response is believed related to hot-waterflooding of the lower portions of the Lower Roseray, an interval which was bypassed during the dry combustion phase due to gas override. Core samples taken near the base of the reservoir indicate residual oil saturations of 17 percent.

The rate increases achieved in the northwest portion of the field, as a result of both dry and wet combustion, were not uniformly shared throughout the field. This is particularly true of areas underlain by the mobile water zone. In areas underlain by mobile water, and where it was possible to maintain water cut at moderately low levels, oil rates were maintained at or above those achieved in the northwest portion of the field during dry combustion. The maintenance of these oil rates is believed to have been, to some extent a result of bottom water pressure maintenance which occurred through the underlying mobile water zone. However, the strength of the aquifer, its ability to maintain pressure through the mobile water zone, and the degree to which bottom water flood has occurred within the Lower Roseray has not been determined.

HORIZONTAL WELL OPPORTUNITY

Having created a secondary gas cap overlying a largely unswept section of the Lower Roseray, the opportunity exists to improve project economics by producing from horizontal wells situated near the base of the reservoir. Given current fluid distributions within the reservoir it is believed that volumetric sweep efficiency can be improved, recovery and rates increased, and operating cost reduced using a vertical displacement process involving combustion gas cap expansion and gravity drainage. This process would include the creation, maintenance, and expansion of a gravity stabilized combustion gas cap, and downward displacement of oil into horizontal producers situated beneath the gas cap.

Results to date, indicate that horizontal wells drilled below the combustion gas cap, improve oil rates and result in lower operating costs by minimizing production of the gas cap. Conversion to a vertical gas displacement process, with pressure maintenance through the injection of air at the top of the reservoir is currently under consideration. Such a process, involving the downward displacement of oil by gas, has been proposed by several authors[2-6] Butler et al.[7] explained the theory of the process and derived equations for the calculation of the maximum rate, or critical rate, for oil production without gas coning.

With respect to the application of this process in the Battrum Field, the greatest challenge is that of achieving and maintaining economic oil production at rates below the critical rate described by Butler. This would involve positioning the horizontal producer far enough below the gas cap to minimize gas coning, yet far enough above the zone of mobile water to minimize water production. By reducing or eliminating water injection into the producing zone, water production may be reduced. However, reduced water injection would require that pressure maintenance be provided by increased air injection into the combustion gas cap.

Two horizontal wells have been drilled, and their results are currently being evaluated and simulated to evaluate the potential of the vertical displacement process. This work will also address the questions of optimum well position and pressure maintenance strategy. Such a strategy is required because conversion to a vertical process would involve significant realignment of injection and production.

HORIZONTAL WELL DEVELOPMENT

In December 1992, 16D-20/3A-28-18-17W3, the first horizontal well was drilled and completed in the thick Lower Roseray sands on the west side of the Battrum field. The horizontal section, 610 metres in length, was drilled from west to east, perpendicular to the updip western erosional edge (Figure 5). The well was completed with a 137.9 mm slotted liner. The heel and toe of this well are within 870 metres and 555 metres respectively from the nearest injection well, situated at 6-28-18-17W3. Although vertical pay thickness is approximately 15 metres along the length of the well, the heel of the well appears to be situated in or above sands having permeabilities somewhat lower than those associated with sands occurring toward the centre of the field. Figure 10 illustrates the profile of the well, and its position with respect to the overlying gas cap and the underlying mobile water zone.

Net oil production from this well is currently 62.1 m^3/d, ten times that of nearby vertical wells (Figure 11). Oil rate has continually increased as gross fluid rate has been gradually increased. Although the well originally produced clean oil, water cut has gradually increased and is currently at 45%, somewhat lower than the vertical well average of 60% for that portion of the field. Gas-oil ratio is currently 18 m^3/m^3, well below the area average of 350 m^3/m^3. Chemical analyses indicate this produced gas to be combustion gas resulting from high temperature oxidation. Sand production which plagues vertical well oil production has not been a problem in this well. During the first year of production this well produced 16,745 m^3 of oil, as compared to an average first year oil volume of 3,665 m^3 for nearby, recently drilled vertical wells producing from the same zone.

The second horizontal well 12B-22/10A-21-18-17W3, was drilled in August 1993. This well, drilled in the "heart of combustion," was intended to evaluate the horizontal well opportunity at a site situated in close proximity to injection. The horizontal section of the well is situated between two Lower Roseray air-water injection wells and no more than 510 metres from the nearest injector (Figure 5). Figure 12 illustrates the profile of this well and its relative position with respect to the overlying gas cap and the underlying mobile water zone. The 406 metres horizontal section in this well was also completed with a 139.7 mm slotted liner.

The second horizontal well produces large volumes of water. Initially the well produced at a water cut of 99%, but as the gross rate was increased to 266 m^3/d, water cut gradually fell to 92%, and a peak net oil rate of 21.3 m^3/d was achieved (Figure 13). For much of the month of November the well was produced at lower fluid rates, resulting in a calendar day oil rate of 9.7 m^3/d average for the month. Nevertheless, both the oil rate and the oil cut achieved in this well are significantly higher than those of surrounding vertical producers. In mid-November 1993, an attempt was made to reduce water cut by isolating the heel of the well which is believed to be positioned near the zone of mobile water. This was accomplished by running an inflatable packer and setting tubing intake at the highest point in the horizontal section of the well. The well was subsequently placed on production at a much lower producing day liquid rate of 52.4 m^3/d. As fluid rate was increased from 52.4 m^3/d to 144.0 m^3/d, water cut decreased from 98% to 95%. Gas-oil ratio increased with increasing gross fluid rate, but has remained well below the area average of approximately 400 m^3/m^3. Fluid level in both horizontal wells has been stable.

Single well simulation of this well indicates that fluid rate and produced fluid composition are highly sensitive to horizontal well position, profile and withdrawal rate. As expected, gas rate is predicted to be high in wells positioned near the gas cap, while water cut is predicted to be high in wells positioned near the mobile water zone. Consequently the vertical position of the well within the Lower Roseray sand has a significant influence on composition of the produced fluids, as does well profile. Simulation also indicates that low points in the well profile lead to cresting of underlying water toward these points, while high points tend to increase the rate of gas production.

Water cut in these horizontal wells also appears to be a function of structural elevation. Just as vertical well production data indicate an updip decrease in water cut due a reduction in mobile water saturation, this same trend is inferred by the horizontal wells. The updip well, 16D-20/3A-28, produces at a water cut of 45%, while the downdip well, 12B-22/10A-21, situated at a structural elevation approximately 5 metres lower, has a water cut of 95%.

Production data from these horizontal wells support the current concept of fluid distribution within the Lower Roseray reservoir, and indicate that horizontal wells positioned below the gas cap decrease gas-oil ratios, reduce well servicing and produce oil which is much easier to treat, and result in lower operating cost. Horizontal well inflow is also much greater that vertical well inflow. Production data and simulation results indicate that produced fluid composition is influenced by horizontal well position and profile. Water cut decreases with increasing height above the mobile water zone, and gas-oil ratio decreases with increasing distance from the combustion gas cap. Water cut is also related to structural elevation, as it appears to decrease with increasing structural elevation.

CONCLUSIONS

Although a horizontal displacement process was originally envisioned for the combustion process at Battrum, there now appears to be a very large vertical component to the displacement process occurring within the Lower Roseray. In addition, vertical producers experience inflow and operational problems because these wells are typically completed within the secondary combustion gas cap. Consequently the use of horizontal producers situated beneath the combustion gas cap and conversion to a vertical displacement process has potential to improve volumetric sweep efficiency in the Lower Roseray reservoir.

Lower Roseray horizontal well results indicate that by positioning horizontal wells between the overlying combustion gas cap and the underlying mobile water zone, productivity can be greatly improved. Servicing and treating costs are also reduced by removing the completion interval from the combustion gas cap. Improved oil recoveries are expected as injection and production sites are aligned consistent with a vertical displacement process involving combustion gas cap expansion and gravity drainage.

Care must be taken to situate the horizontal producer far enough below the gas cap to prevent gas coning, yet far enough above the zone of mobile water to minimize water production. A smooth well profile must also be maintained to minimize the focusing of drawdown, particularly at high points where combustion gas production might occur.

REFERENCES CITED

1. Christopher, J.E.: "The Upper Jurassic Vanguard and Lower Cretaceous Mannville Groups of Southwestern Saskatchewan," Saskatchewan Department of Minerals Report No. 151, 1974.
2. Hagoort. J.: "Oil Recovery by Gravity Drainage," *SPE Journal*, June 1980, pp. 139-150.
3. Carlson, L.O.: "Performance of Hawkins Field Unit Under Gas Drive-Pressure Maintenance Operations and Development of an Enhanced Oil Recovery Project," Paper SPE/DOE 17324 presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, Apr. 17-20, 1988.

4. Kantzas, A., I. Chatzis and F. A. L. Dullien: "Enhanced Oil Recovery by Inert Gas Injection," SPE/DOE Paper 17379, presented at SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, Apr. 17-20, 1988.
5. Ostapovich, E., and F. N. Pebdani: "Method for Enhanced Recovery through a Horizontal Production Well in a Subsurface Formation by In-Situ Combustion," *U.S. Patent 5211230*, May 18, 1993.
6. Kisman, K.E., and E. C. Lau: "A New Combustion Process Utilizing Horizontal Wells and Gravity Drainage," presented at the CIM 1993 Annual Technical Conference, Calgary, Alberta, May 9-12, 1993.
7. R.M. Butler, and V. Kanakia: "Recovery of Heavy and Conventional Oils from Pressure-Depleted Reservoirs Using Horizontal Wells," Paper No. 8 presented at the CIM/CANMET 5th Saskatchewan Petroleum Conference, Regina, Saskatchewan, (Oct. 18-20, 1993.

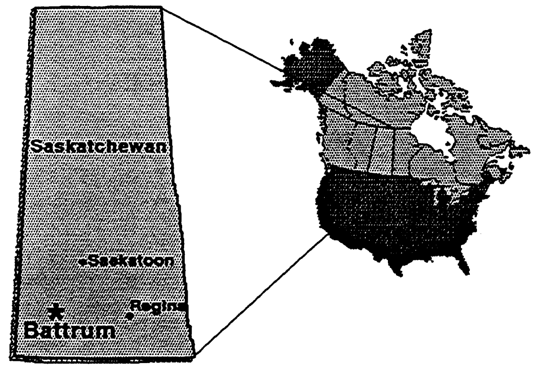


Fig. 1 - Location of the Battrum Field

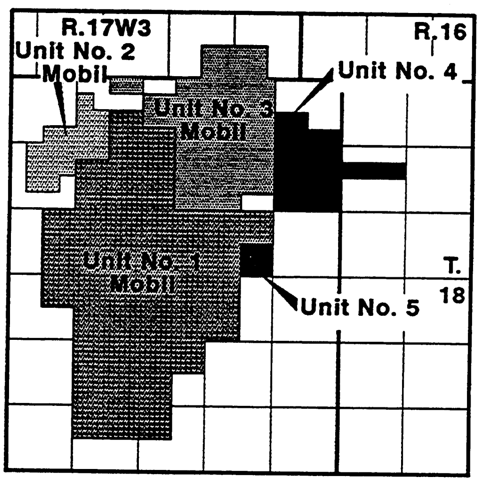


Fig. 2 - Battrum Units

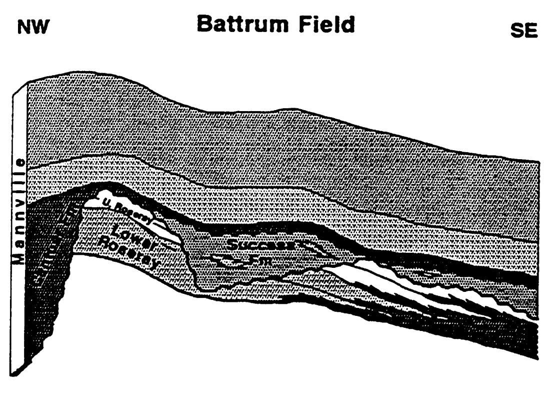


Fig. 3 - Structural Cross Section

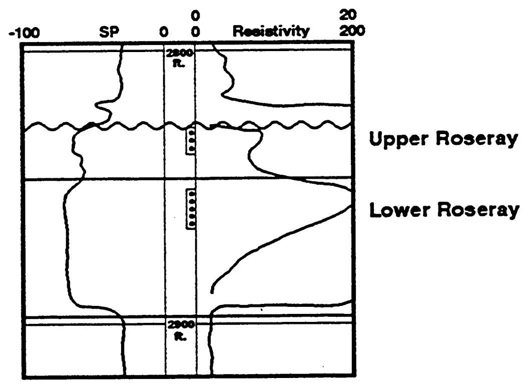


Fig. 4 - Type Log

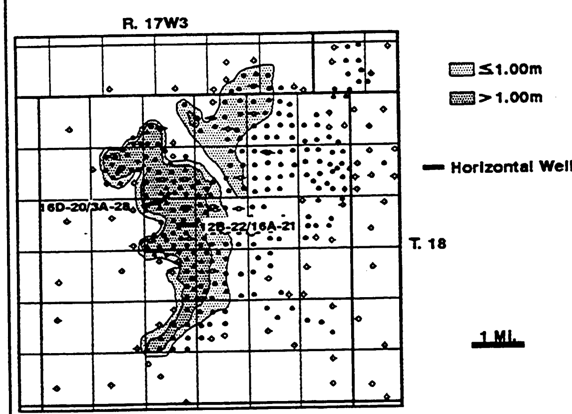


Fig. 5 - L. Roseray
Hydrocarbon Porosity Thickness

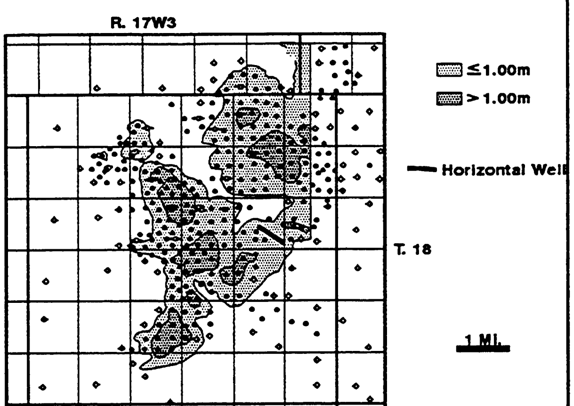


Fig. 6 - U. Roseray
Hydrocarbon Porosity Thickness

Battrum
Fluid Characteristics

• Oil Gravity	18 °API
• Oil Viscosity	70 cP
• Bubble Point Pressure	1393 kPa
• Formation Volume Factor	1.024 m^3/m^3
• Solution GOR	4.5 m^3/m^3

Fig. 7

Battrum

Rock Characteristics

- **Jurassic Roseray Formation**
- **Poorly Consolidated / Well Sorted / Fine Grained Sands**
- **Average Depth** 950 m
- **Porosity** 25 - 35%
- **Permeability** 1 - 10 Darcies
- **Water Saturation** 15 - 60%
- **Temperature** 46° C
- **Original Pressure** 8500 kPa

Fig. 8

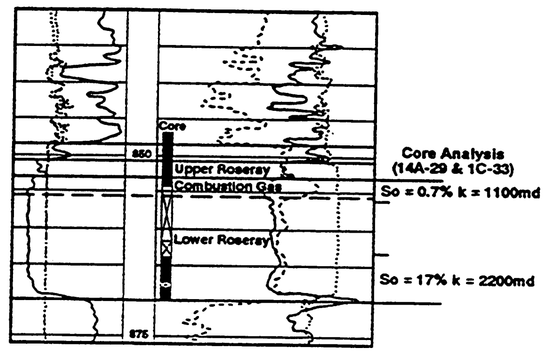


Fig. 9 - Combustion Gas Cap (OBS 14A-29-18-17W3)

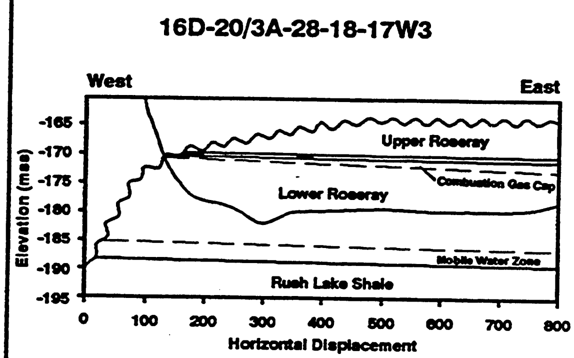


Fig. 10 - Well Profile

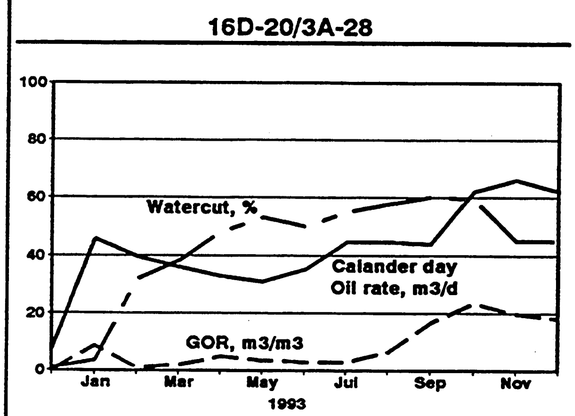


Fig. 11 - Performance as a Function of Time

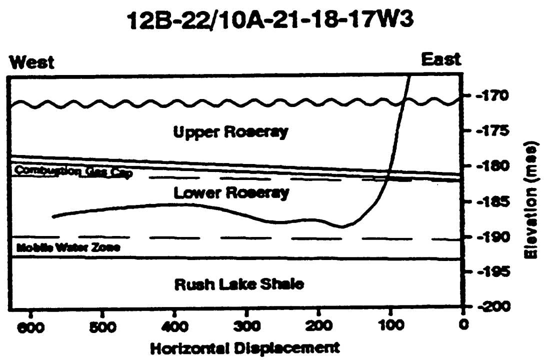


Fig. 12 - Well Profile

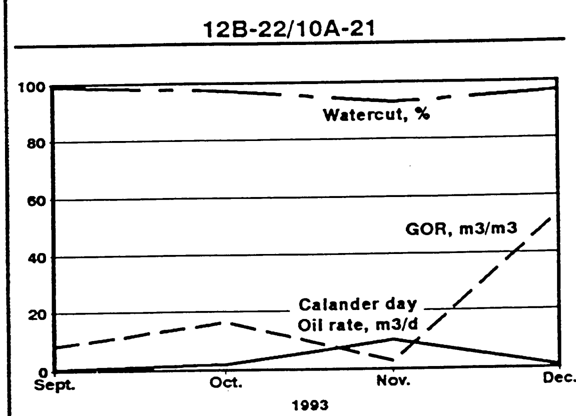


Fig. 13 - Performance as a Function of Time

Shallow Oil Production Using Horizontal Wells with Enhanced Oil Recovery Techniques

by R. M. Satchwell, L. A. Johnson Jr., Western Research Institute, Laramie, Wyoming, and R. Trent, University of Alaska, Fairbanks, Alaska

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

Millions of barrels of oil exist in the Bartlesville formation throughout Oklahoma, Kansas, and Missouri. In an attempt to demonstrate that these shallow heavy oil deposits can be recovered, a field project was undertaken to determine the effectiveness of enhanced oil recovery techniques (EOR) employing horizontal wells.

Process screening results suggested that thermal EOR processes were best suited for the recovery of this heavy oil. Screening criteria suggested that in situ combustion was a viable technique for the production of these reserves. Laboratory combustion tube tests confirmed that sufficient amounts of fuel could be deposited.

The results of the in situ combustion field pilot were disappointing. A total overall recovery efficiency of only 16.0 percent was achieved. Results suggest that the combustion front might have moved past the horizontal well, however elevated temperatures or crude upgrading were not observed. Factors contributing to the lack of production are also discussed.

INTRODUCTION

Early work in the Chetopa field was performed by Tenneco between 1965 to 1967. The work was designated as a research effort to develop laboratory and field data for steam flooding. Emphasis of the work was on technology oil, however; approximately 70 percent was used as fuel resulting in a net production of 21,000 barrels.[1]

Recent production efforts were initiated in this field by Kaycee Oil Company and Shallow Oil Limited in 1987. This work focused on using horizontal wells. Two parallel horizontal wells, 100 feet apart, were drilled and completed within the reservoir. During the drilling of the second horizontal well, steam injection was initiated in the first horizontal well. The production results of the steam injection during drilling were encouraging. After completing the second well, a steam huff-n-puff process was initiated. A fourteen day injection period was followed by a four day soak period. After installing a pump, hot water and a small amount of oil were recovered at the injection well. A second cycle using a larger boiler produced similar results. Failure of the project was attributed to insufficient heat input and an inadequate drive mechanism.

A project was initiated to determine the causes of failure of previous attempts and to devise appropriate EOR strategies for the Chetopa field. Items to study included reservoir characterization and EOR process screening using laboratory tests. Based on the results, a pilot demonstration was to be performed using the most technically feasible EOR technique.

Geological Assessment

The Chetopa field is located in southeastern Kansas as shown in Figure 1. The production horizon, Figure 2,

References, tables and illustrations at end of paper.

consists of Bartlesville sandstone, also known as the Bluejacket. This sandstone is within the Krebs Subgroup of the Cherokee Group. According to Johnson,[2] the Bartlesville sandstone of the Chetopa field was deposited primarily as a point bar with associated channel fill surrounding the sand body. Although the Bartlesville sandstone in its entirely is as thick as 60 feet, the highly permeable portions corresponding to the point bar are only half as thick.

Log analyses indicate that porosity ranges from 26 to 30 percent from the top to the base of the point bar. In the region of interest, the water saturation ranged from 29 to 38 percent. Oil-in-place was determined to be approximately 1.61 MMbbl (9.1 MMbbl per acre). The pay zone (12 feet) has been limited to only the continuous and permeable portion of the point bar and omits any of the adjacent channel fill sands. A Bartlesville isopach map is shown in Figure 3. From log analyses, the point bar was located and is presented in Figures 3 and 4. Figure 4 illustrates the highly permeable point bar and presents the highest oil saturated sands which are up-dip of the water-oil contact. Other pertinent reservoir parameters used in this work are presented in Table 1.

Since log data from recently drilled wells was unavailable, a 40 foot length of core was retrieved from the Chetopa field for analysis. Every foot was plugged to determine porosity and fluid saturations. The average porosity for the point bar was approximately 24.3 percent. The average oil and water saturation for the target zone was determined to be 58.4 and 18.8 percent, respectively.

Enhanced Oil Recovery Processes Screening

EOR techniques were reviewed to find the most technically feasible process to apply to the Chetopa field. These reviewed techniques included thermal, chemical, miscible, and non-miscible processes. Using screening criteria established by Taber and Martin,[3] an initial screening was performed.

Initial screening revealed that miscible gas processes would not work in this case. In order for miscibility to be attained, the oil must contain a relatively high concentration of intermediate hydrocarbons (C_2 - C_6). This hydrocarbon range is not present in the low gravity crude oil of the Chetopa reservoir. Similarly, initial screening showed that chemical processes are not suitable for this field. In these processes, the oil must be displaced with another fluid. The large crude oil viscosity (3,000 cP) causes extremely poor mobility ratios that lead to the fingering of the displacing fluid. This fingering leads to poor displacement efficiency, and hence poor areal sweep efficiency. The results from the initial screening favored thermal stimulation. Heating the oil to 250° F would make the oil more mobile. This heating could be accomplished by either steam injection or in situ combustion. Therefore, advanced screening was performed for both steam injection and in situ combustion.

Advanced steam flood screening was performed by using criteria and correlations compiled by Chu [4] The results of this evaluation showed that steam injection was not an attractive alternative for the Chetopa field. The shallow depth of the reservoir would limit the amount of useful heat that could be injected into the reservoir. The thin reservoir would cause a large amount of useful heat to be lost to the over- and underlying rock strata. Data given by the Interstate Oil Compact Commission[5] indicated that a 15-foot thick reservoir would result in a cumulative heat loss of 70 percent. As a result of this heat loss and the formation of a water bank, sweep efficiency would be reduced. Farouq Ali[6] showed that a maximum obtainable sweep efficiency would only be 50 percent. Using a steam-oil correlation from the literature,[4] a value of 11.3 barrels steam per barrel of oil was obtained for the Chetopa field. Typically, projects that use produced oil as fuel for steam generation required one barrel of oil to produce about 13-14 barrels of steam. Therefore, an SOR of 11.3 is deemed marginal for oil recovery from the Chetopa field.

Advanced screening of in situ combustion was performed using screening guides provided by several authors.[7,8,9,10,11,12] Two major items of concern were identified, i.e., high crude oil viscosity and shallow depth of the reservoir. The high crude viscosity will make it difficult to push the unheated oil through the reservoir to the production well. Shallow depth of the reservoir was of concern because during air injection, the bottom hole pressure must be maintained less than the fracture pressure of the reservoir. If fracturing occurs, large amounts of air could be lost to nonproductive intervals. Nevertheless, sufficient air injection rates must be maintained to sustain combustion. The concern pertaining to the viscosity of the oil could be circumvented using reverse combustion, however since this method has not met with a large degree of technical success, the use of this technique was dismissed.

The results of the EOR screening suggested that in situ combustion is the most technically feasible process to produce oil. From the advanced screening, injection rate limitations caused by the reservoirs shallow depth and the large oil viscosity could be detrimental to the in situ combustion process. To determine if these concerns were justified, combustion tube tests were performed.

Combustion Tube Tests

A major consideration related to the in situ combustion was the amount of fuel deposition and associated air requirements. In the advanced screening, the use of various correlations produced a large degree of uncertainty in the amount of fuel deposition with ranges from 0.85 to 2.80 lb/ft^3. To provide better assessment of this data, two vertical combustion tube tests were performed with reservoir material. These tests were also performed to define the effects of oil saturation and reduced air injection rate.

In the first test, the average oil and water saturation was approximately 50 and 9 percent, respectively. During this test, air was injected at a rate of 0.09-0.10 scfm. In this test, a peak temperature of 969° F was obtained. The results of this test indicated a fuel content of 2.10 lb/ft^3 and approximately 1.13 scf of gas production per cubic foot of reservoir material. Gas analyses showed that the test produced 16.36 volume percent of carbon dioxide, 3.42 volume percent carbon monoxide, with remainder being nitrogen.

To investigate the effect of saturation levels, a second test was performed with water and oil saturations of 26 and 27 percent; respectively. Furthermore, air injection rates were set at approximately 0.025 scfm, to determine if the combustion front would extinguish itself. In this test, the peak temperature obtained was approximately 893° F. The results of this tests indicated that a fuel content of 2.30 lb/ft^3 could be achieved. Approximately 1.21 scf of gas was produced per cubic foot of reservoir material. Produced gas was composed of 17.65 volume percent carbon dioxide, 3.21 volume percent of carbon monoxide, and the remainder being nitrogen.

In both tests, upgraded oils were produced. These tests indicated that sufficient oil volumes and fuel contents are present in the Chetopa field. Lower oil saturations, higher water saturations, and lower air injection rates resulted in lower peak temperatures, higher fuel contents, and higher produced volumes of carbon dioxide. These results were consistent with data reported in the literature. All data were analyzed using the method proposed by Nelson and McNeil[13] and the following results were determined by averaging of the two tests. Based on the existing horizontal well pattern and vertical wells located between the horizontal wells, and assuming a burning rate of 0.125 feet per day and a volumetric sweep efficiency of 100 percent, the maximum oil production rate was projected to be approximately 21.3 barrels per day with the total oil recovered to be approximately 813 barrels per acre-ft. Since the oil-in-place is approximately 1,086 barrels per acre-ft, than the potential recovery would be approximately 74.8 percent. The data also indicated that lower injection rates and pressures could be employed while still sustaining combustion.

Field Demonstration

A single vertical well was drilled in the eastern portion of the Chetopa structure to verify the target zone. From the work of Thomas,[14] it was estimated that the maximum radial distance that would sustain combustion was less than 150 feet. To obtain a vertical coverage of 70 percent for the combustion front, over a distance of 100 feet, a gas injection rate of 377 scf per ft-hr was required. However, to prevent fracturing of the formation, a maximum injection rate of only 300 scf per ft-hr could be achieved. Based on this information, and to investigate the effects of injection well spacings, the well spacings were established at 200 and 100 feet for the three vertical wells as shown in Figure 5. Relative locations of the wells were determined from drilling records and survey data.

Thomas[14] indicates that higher combustion front temperatures occur above the horizontal plane of the ignited interval. Thus, in order to minimize gas production and maximize oil production, the location of the horizontal production wells in the lower portion of the target zone seemed adequate. Furthermore, since the horizontal wells were located approximately 50 feet on either side of the vertical wells, the production wells would act as containment of the combustion front.

After the vertical wells were drilled and completed, an ignitor was attached to 1-inch tubing and lowered into Vertical well #3. This ignitor was a propane-fired burner that consisted of a ignitor assembly, flame arrestor, burner nozzle and a shell. A rubber boot was attached to the shell outlet of the burner to provide a liquid seal during insertion into the wellbore. The burner was capable of operating in a pressure range of 20-150 psig with a heat output capacity of 0.5-1.5 MBtu per hour.

Both propane and air were premixed at the surface and injected down the tubing through the burner. The burner was ignited using the ignitor assembly. Ignition of the formation was accomplished after 36 hours of heat injection. After which, air injection was continued and propane flow was suspended.

Air injection was continued for 80 days. A total of 40 barrels of oil were produced. Gases were sampled and analyzed from both horizontal production wells. The results of these analyses for horizontal production wells #1 and #2 are shown in Figures 6 and 7, respectively. Note that the two production wells did not produce similar gas analyses. Carbon dioxide concentrations observed were as high as 20 percent. Other interesting observations included the failure to detect increased temperatures in the production wells and the lack of any upgrading of the crude oil.

High oxygen and low carbon dioxide concentrations observed in the horizontal well #1 indicate that the combustion front might have moved toward the horizontal well #2, and not in the direction of the horizontal well #1. If the combustion front was moving preferentially toward the horizontal well #2 in a radial shape, then the combustion front should have reached the horizontal well #2 after approximately 29 days. The high carbon dioxide concentration and absence of oxygen in the horizontal well #2 during the 31-40 day period tend to support this hypothesis. The preferential burning direction toward horizontal well #2 could have been caused by: (1) failure to sustain complete ignition around the wellbore, (2) directional permeability, or (3) a combination of both factors.

Since there was no upgraded oil production nor any increase in temperature, it appears that the combustion front, due to gravity override, was located near the top of the formation. If one assumes that a 6-inch thick combustion front would produce a 4.2 percent volumetric sweep efficiency (combustion front thickness ÷ formation thickness), then the sweep efficiency for the unburned portion and the overall recovery efficiency can be determined using the method prescribed by Nelson and McNeil.[32] The unburned portion of the reservoir refers to reservoir which is stimulated by the process but not contacted by the burning front. The sweep efficiency of the unburned zone was determined to be approximately 13.2 percent. The overall recovery efficiency was determined to be 16.0 percent for the process.

The poor overall recovery efficiency can be attributed to two major factors. First, crude oil was produced exclusively by reservoir pressure. This prevented the hotter oil from entering the well and hence lowering the overall sweep efficiency of both the unburned and burned portion of the reservoir. Second, the transfer of heat from the burned zone to the rest of the reservoir was minimal. This lack of heating reduced the volumetric sweep efficiency since a reduction in viscosity was not achieved. This transfer mechanism could have been improved by implementing a water-alternating-gas (WAG) injection scheme.

CONCLUSIONS

This project demonstrated the use of horizontal wells with in situ combustion of a heavy oil reservoir. The project results determined the causes of failure for previously attempted oil production techniques and devised an appropriate EOR strategy for the Chetopa field.

Screening identified the most viable EOR process as in situ combustion. The process was tested in the forward mode in laboratory tests and performed in the field as a pilot demonstration. The field test showed that in situ combustion could be sustained at shallow depths. Gas analyses identified the movement of the combustion front to the production well. Movement past this well was identified by the reduction of carbon dioxide levels and an increase in the concentration of the oxygen in the product gas.

The overall recovery efficiency was determine to be approximately 16 percent. This lack of oil production was a result of the inability to remove the heavy oil from the formation around the production wellbores and the frontal advancement characteristics of forward in situ combustion. Improvements in recovery could be obtained by implementing a closed loop pumping system that would preheat the production wellbore. By changing the frontal advancement characteristics of the combustion front, such as by using a WAG injection process, improved sweep efficiencies and higher recovery would result.

ACKNOWLEDGMENTS

The authors wish to thank Drs. David Whitman and William Iverson for their technical contributions to this work. We would also like to thank the United States Department of Energy for their assistance and support of this project.

REFERENCES

1. Kaycee Oil Company Internal Records.
2. Johnson, C.T.L.: "Environment of Deposition of the Pennsylvanian Bartlesville Sandstone, Labette County, Kansas," Geology Masters Thesis, Texas A&M University, 1973.
3. Taber, J.J. and F. D. Martin: "Technical Screening Guides for the Enhanced Recovery of Oil," *Society of Petroleum Engineers*, Paper No. 12069, October 1983.

4. Chu, C.: "State-of-the-Art Review of Steamflood Field Projects," *Journal of Petroleum Technology*, October 1985.
5. Interstate Oil Compact Commission: *Improved Oil Recovery*, March 1983.
6. Farouq Ali, S.M.: "Current Status of Steam Injection as a Heavy Oil Recovery Method," *Journal of Canadian Petroleum Technology*, January-March 1974.
7. Poettmann, F.H.: "In Situ Combustion: A Current Appraisal," *World Oil*, Part 1, April; Part 2, May 1964.
8. Geffen, T.M.: "Oil Production To Expect From Known Technology," *Journal of Petroleum Technology*, May 1973.
9. Lewin and Associates, Inc.: "The Potential and Economics of Enhanced Oil Recovery," Federal Energy Administration., Report B76/221, 1976.
10. Chu, C.: "A Study of Fireflood Field Projects," *Journal of Petroleum Technology*, February, 1977.
11. Chu, C.: "State-of-the-Art Review of Fireflood Field Projects," *Journal of Petroleum Technology*, January 1982.
12. Iyoho, A.W.: "Selecting Enhanced Oil Recovery Processes," *World Oil*, November 1978.
13. Nelson, T.W. and J. S. McNeil Jr.: "Thermal Methods Provide Three Ways to Improve Oil Recovery," *Oil and Gas Journal*, January 1959.
14. Thomas, G.W.: "A Study of Forward Combustion in a Radial System Bounded by Permeable Media," *Journal of Petroleum Technology*, October 1963.

SI Metric Conversion Factors

bbl	x	1.589 873	E-01	=	m^3
ft	x	3.048	E-01	=	m
acre	x	4.047	E+3	=	m^2
°F		(°F -32)/1.8		=	°C
lbm/ft^3	x	1.601 169	E+01	=	kg/m^3
ft^3	x	2.831 685	E-02	=	m^3
psi	x	6.894 757	E+00	=	kPa
Btu	x	1.054 8	E+03	=	Joules

Table 1. Reservoir Parameters

Reservoir Properties		
Porosity, %	28	
Permeability, mD	100-500	
Oil Saturation, %	50	
Net Thickness, ft	15	
Depth, ft	100-120	
Reservoir Temperature, °F	65	
Formation Type	Sandstone	
Oil Elemental Analysis		
Carbon	86.7 volume percent	
Hydrogen	11.4 volume percent	
Nitrogen	0.3 volume percent	
Sulfur	0.2 volume percent	
Oxygen	1.0 volume percent	
Reservoir Viscosity - Temperature Dependence		
Temperature, °F	**Viscosity, cP**	
60	3,165	
100	1,165	
140	241	
Gravity - Temperature Dependence		
Temperature, °F	**Specific Gravity**	**API Gravity, degrees**
60	0.960	16.0
100	0.947	18.2
140	0.940	19.2

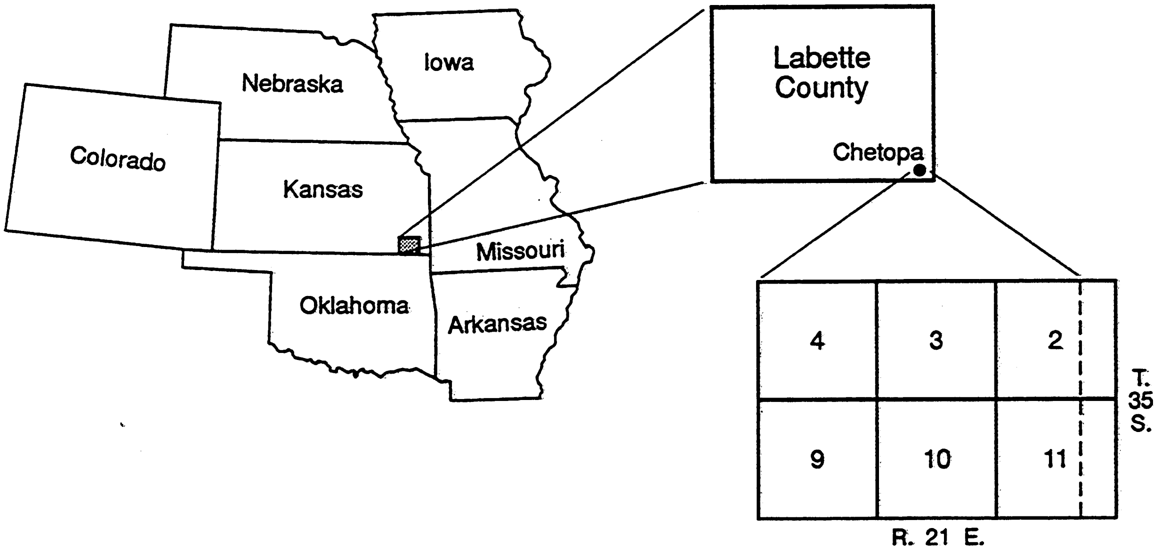


Figure 1. Chetopa Oil Field Location

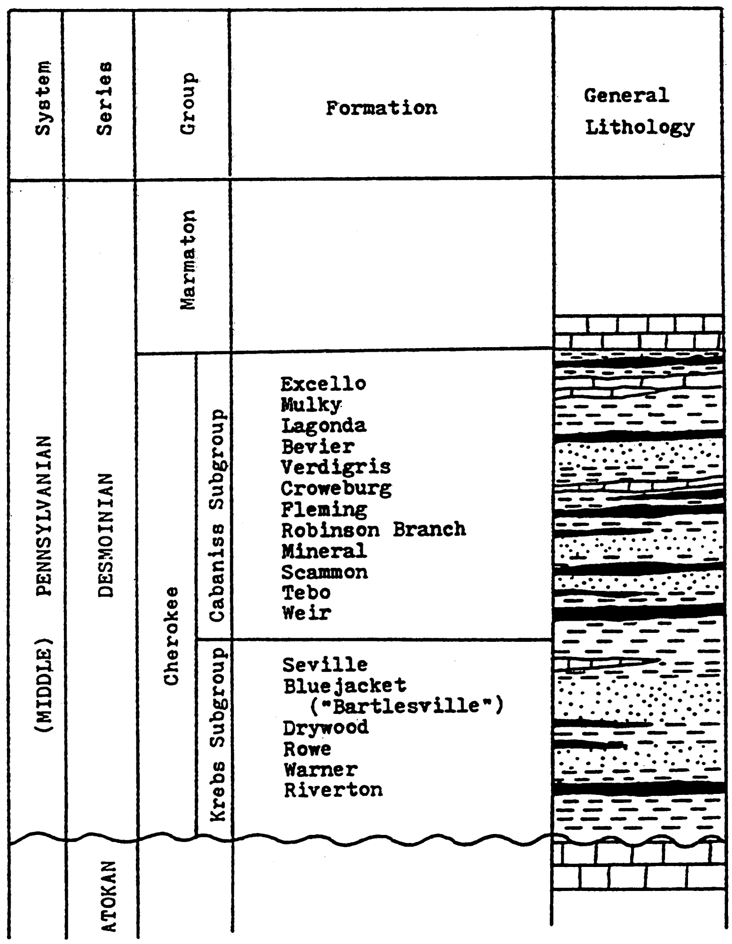


Figure 2. Relevant Stratigraphic Chart

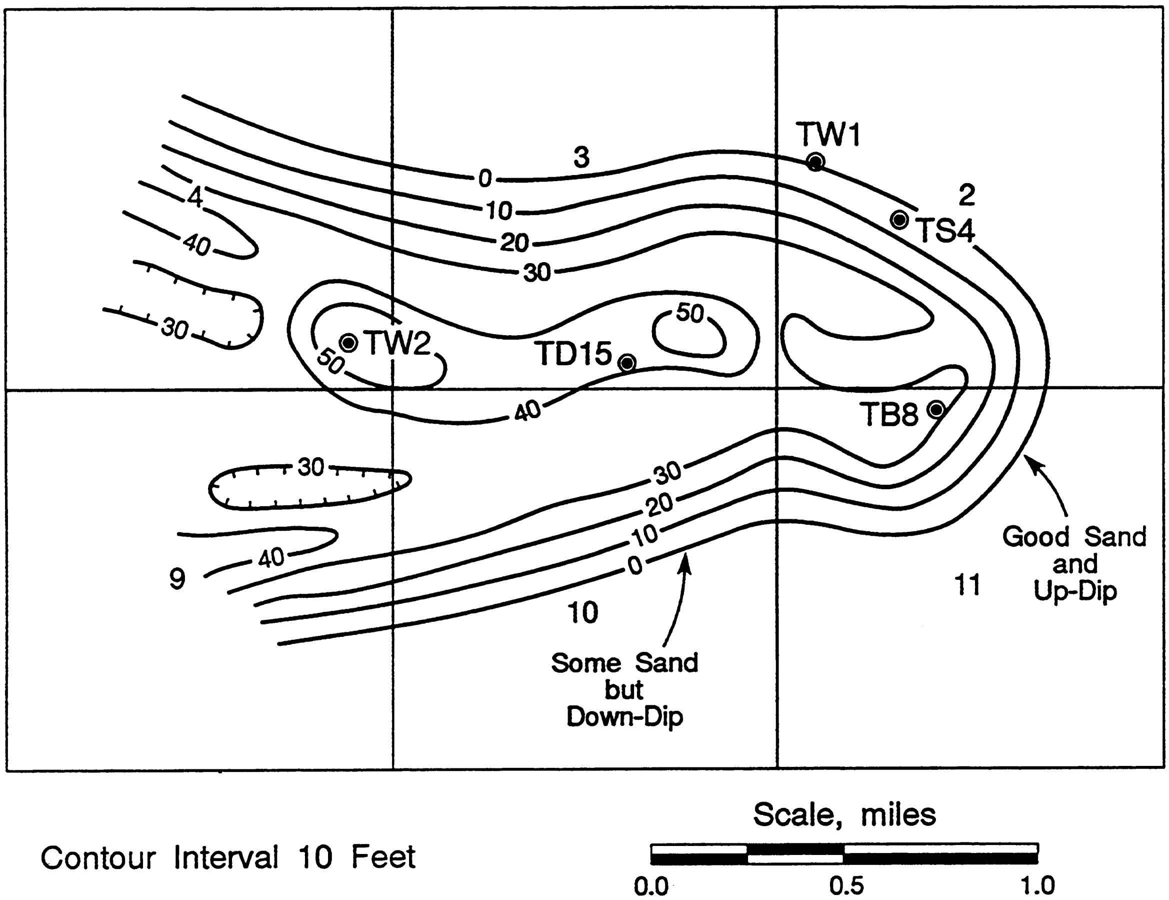


Figure 3. Bartlesville Isopach Map

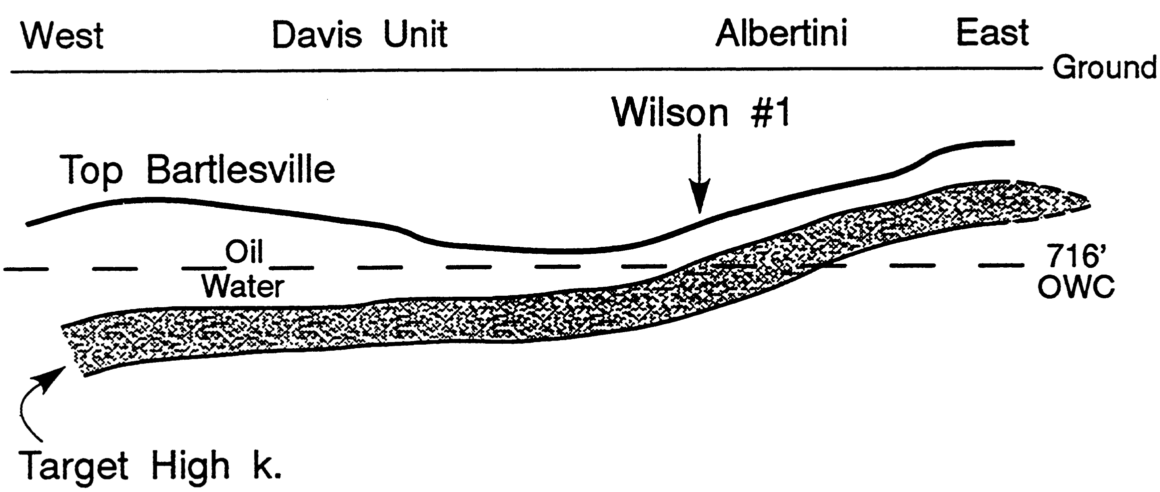


Figure 4. Schematic of Permeable Point Bar

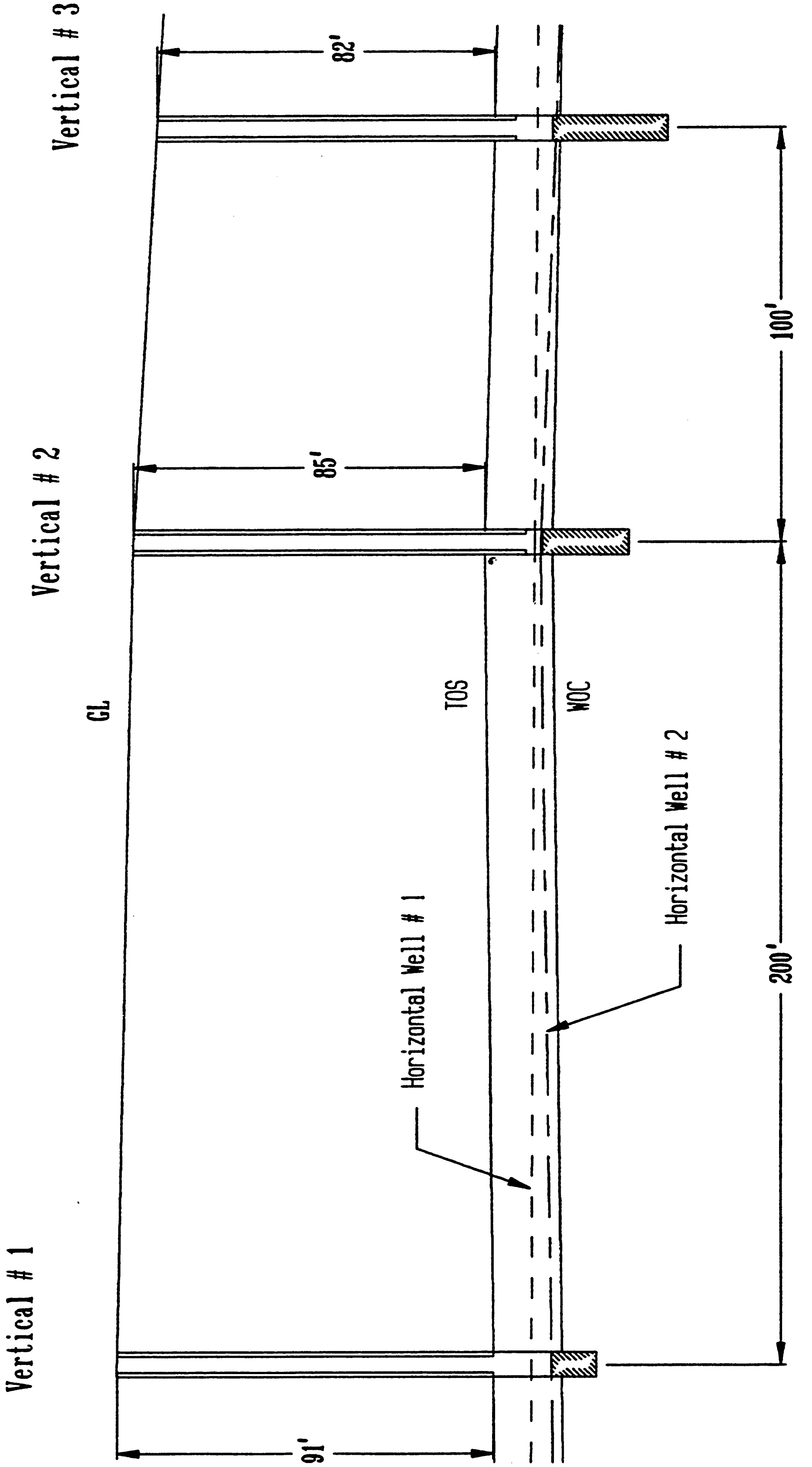


Figure 5. Vertical and Horizontal Well Orientations

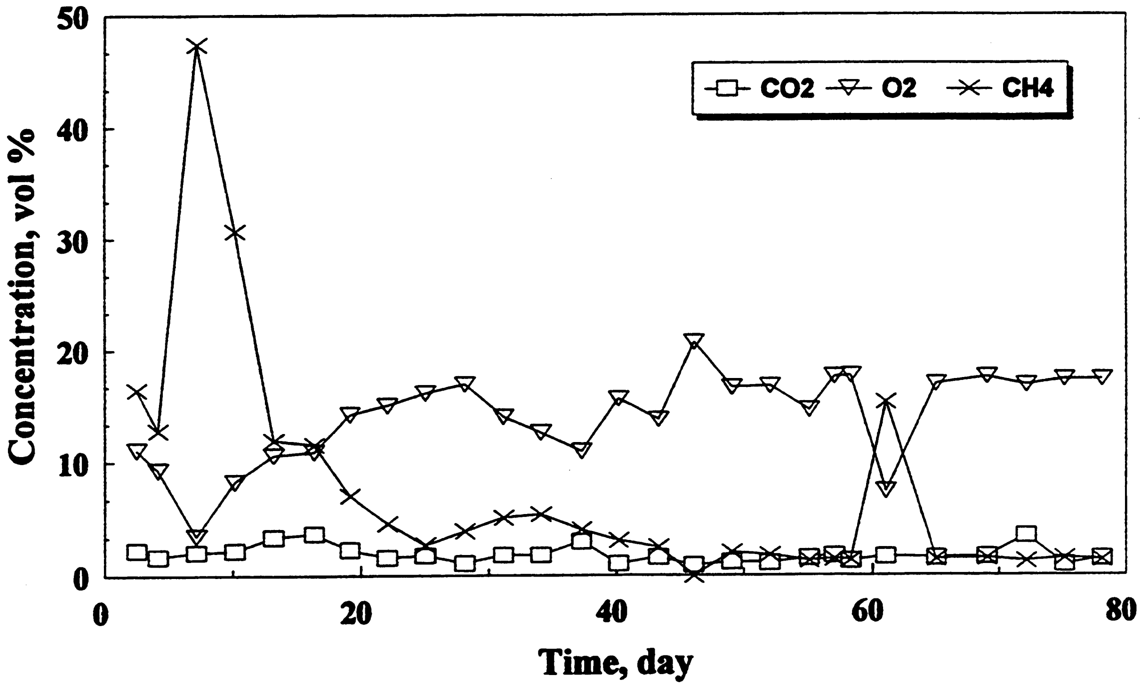


Figure 6. Gas Analyses of Horizontal Production Well #1

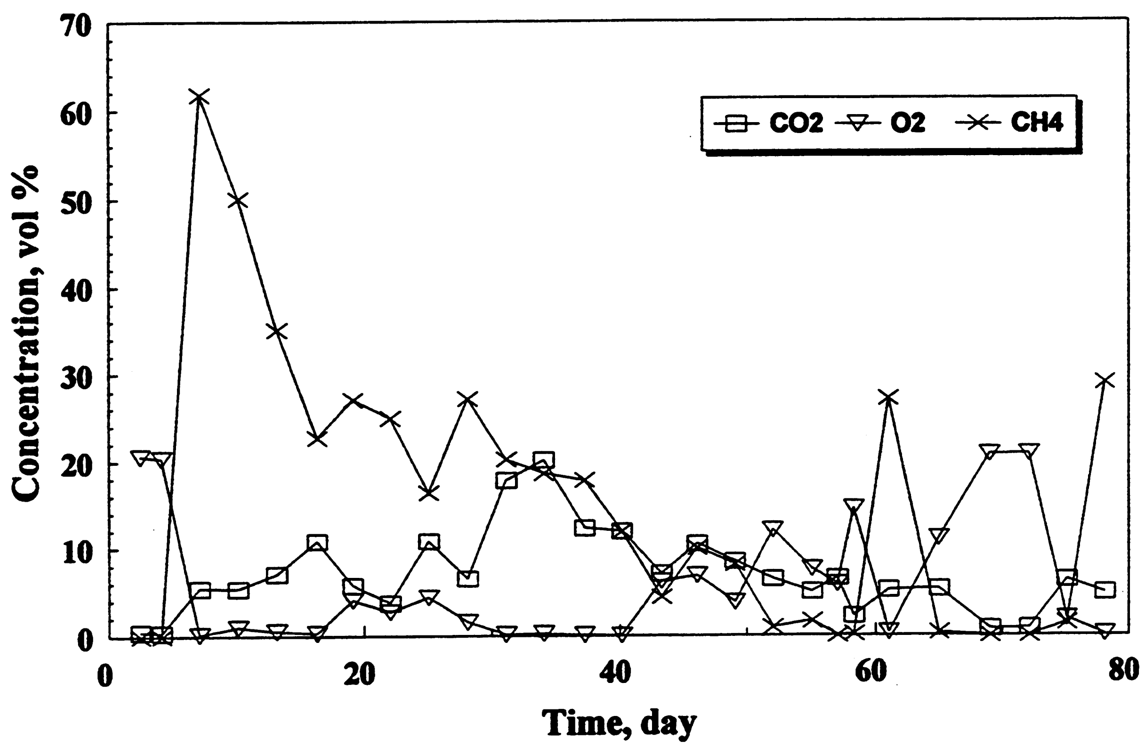


Figure 7. Gas Analyses of Horizontal Production Well #2

Naval Petroleum Reserve No. 3 (NPR-3), Teapot Dome Field, Wyoming: Case History of the In Situ Combustion Pilot Operation

by P: S. Sarathi, D. K. Olsen, BDM-Oklahoma, and C. Ray Williams, U.S. DOE, Casper, Wyoming

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

ABSTRACT

Naval Petroleum Reserve No. 3 (NPR-3) is a federally owned oil field that has been in operation since 1922 and has produced more than 15 million barrels of oil since full production began in 1976. The Shannon sandstone is the shallowest and most productive of nine producing formations at NPR-3. Since only 5% of the Shannon's estimated 144 million bbl of original oil in place (OOIP) was estimated to be recoverable by primary means, studies were undertaken in 1978 to determine the most suitable enhanced oil recovery (EOR) method which would merit a pilot test and could ultimately lead to a fieldwide application.

From this 1978 analysis, an in situ combustion (fireflood) process and polymer augmented waterflood were chosen for pilot testing. This paper describes the results of the in situ combustion pilot test and the influence of geology on project performance.

The pilot implemented in December 1981 was brought to conclusion in April 1986. It exhibited positive production response. However, all monitoring parameters indicated a very inefficient burn. Because of fluid interactions between patterns and commingling of gas and liquids produced from the Upper and Lower Shannon intervals, it was difficult to determine exactly the reasons for the inefficiency.

Post-pilot core analyses indicate that only the Upper Shannon is conducive to fireflooding, and the fractures and faults greatly influenced the transport of injected fluid. Injected air channeled through fractures resulting in poor oxygen utilization in both pilot area and off pilot production.

Over the life of the pilot, the project produced over 72,500 bbl of oil, of which about 17,000 bbl were estimated to be produced from the 5-acre pilot area. The balance came from producers in the vicinity of the pilot. It has not been determined whether the off-pilot response is truly secondary (incremental) production by represurization or it is simply an accelerated production that would have eventually been produced via primary means.

In general, the Shannon's response to combustion was positive. Since the pilot was implemented at the time of rising oil prices, the project proved to be marginally economical despite a high air-oil ratio.

INTRODUCTION

The U.S. Department of Energy (U.S. DOE), through its contractor Lawrence-Allison & Associates West, conducted a dry in situ combustion pilot test in the Shannon reservoir at the Naval Petroleum Reserve No. 3 (NPR-3) over a 5-year period beginning December 1981. The purpose of the pilot was to test the technical and economic viability of the process in a highly faulted and naturally fractured sandstone reservoir. This paper reviews the in situ combustion (fireflood) pilot performance and discusses the influence of geology on pilot performance.

BACKGROUND

The NPR-3 (also known as the Teapot Dome field) is a U.S. government-owned oil field located about 35 miles

References, tables and illustrations at end of paper.

north of Casper in Natarona County, Wyoming (Fig. 1). The reserve was established by an executive order from President Wilson in 1915. The field is operated by the U.S. DOE through its management and operating (M&O) contractors. Lawrence-Allison & Associates West was the operating contractor at the time the in situ combustion pilot was implemented. F. D. Services is the current operating contractor.

NPR-3 is situated on the Teapot Dome Anticline in Powder River basin, Wyoming. Teapot Dome is the southern extension of the much larger Salt Creek Anticline. The NPR-3, comprised of 9,481 acres and the Shannon is the shallowest and most productive of the nine producing reservoirs at NPR-3. During fiscal year 1981, prior to the implementation of the in situ combustion pilot, the total field production was approximately 3,200 bbl/d (BOPD) oil, of which about 900 BOPD was produced from the Shannon reservoir. Since only 5% of the Shannon's original 144 MM bbl of original oil in place (OOIP) was anticipated to be recovered by primary means, a study was conducted by a reservoir consulting firm in 1978 to evaluate the enhanced oil recovery (EOR) potential of Shannon reservoir. The study identified polymer augmented waterflood and in situ combustion as the two most attractive EOR processes for Shannon from a technical and economic point of view. Steamflood was predicted to be the third best. As a result of this study, a polymer augmented waterflood pilot and an in situ combustion pilot were implemented in late 1981 and finished in early 1986. The in situ combustion pilot test is discussed in the following section. Grooms and Schulte[1] present the results of the polymer augmented waterflood.

RESERVOIR DESCRIPTION

The Shannon reservoir is a Cretaceous offshore bar sand found at depths of 300 to 500 ft at NPR-3. It has an areal extent of 3,500 acres and produces from two sandstone intervals which are separated by a shaley siltstone. The Upper Shannon is 47 ft net thick and the Lower Shannon is 25 ft net thick. The maximum gross thickness is 100 ft.

Log and core analysis data indicated that the Shannon is a naturally fractured shaley sand with a weighted average porosity of 18% and a weighted average air permeability of 63 mD. The oil is a sweet 32° API light crude with a viscosity of 10 cP at the reservoir temperature of 65° F. The initial oil saturation ranges between 35% and 60% with a weighted average of 40%.

To explain the EOR performance, a detailed geologic characterization of the Shannon reservoir was carried out in 1985. Core analyses, along with SP, gamma ray, restivity, and porosity logs were utilized to characterize the Shannon. Core and log description studies identified the depositional environment of the Shannon reservoir as bar margin, interbar, bioturbated shelf sandstone and bioturbated shelf siltstone (Fig. 2). Most of the oil bearing rock at NPR-3 is comprised of bioturbated shelf sandstone. Based on their geological model for the Shannon sandstone, Martinsen and Tillman[2] stated that interbar facies have limited productive potential and bioturbated shelf sandstone has no productive potential. However, Porter[3] concluded that, based on cumulative oil production from the Shannon in Boulder field, Colorado, natural fractures rather than best sandstone was a major contributor to production. As discussed later, natural fractures and facies have been found as a prime influence on production.

Geological investigations indicated that the Shannon at NPR-3 is extensively faulted and naturally fractured. The strike of the faults have a southwest-northeast orientation, ranging from 0 to 150 ft in displacement.[4] The investigation also revealed that the Upper Shannon was of better quality than the Lower Shannon and that porosity and permeability decreased from top to bottom in each sandstone. As a result of geological characterization, the pore volumes and oil saturations for facies represented in the Upper and Lower Shannon were revised and the initial oil in place (IOIP) and EOR resource potential were estimated to be 144 MM STB and 30 MM STB. Table 1 summarizes the petrophysical characteristics of Upper and Lower Shannon. Further details of the Shannon reservoir geologic characterization can be found in Reference 5.

PROJECT DEVELOPMENT

Prepilot Activities

Prior to implementation of the in situ combustion pilot, combustion calculations were made to establish design criteria. These calculations were made using the published correlations for fuel consumption and air requirements and are based on the reservoir properties of the pilot area. No combustion tube tests were conducted prior to implementation because it was thought that the calculated values were sufficiently accurate for design purposes.

Application of correlations for the properties of the Shannon reservoir in the pilot area indicated that the air consumption was expected to be 7.8 MMscf/ac-ft with an air-oil ratio of 14 Mscf/bbl for oil produced from the burned volume of the reservoir. The minimum combustion front velocity was calculated to be 0.125 ft/D which corresponds to a minimum air flux of 22.5 scf/ft^2-D. The combustion calculations are summarized in Table 2.

Test Site

The in situ combustion pilot test site was selected on the basis of evaluation of reservoir characteristics determined by log and core analysis. The selected site was located on the crest of the Shannon structure in an area in Section 3, that was believed to be free of fractures and fault planes. However, as discussed in a later section, this was not to be the case and significant volumes of the injected air and combustion gases were produced from off-pilot wells, indicating channeling due to fractures.

Figure 3 shows the pilot layout, which consisted of four 2.5 acres inverted 5-spot patterns. These include nine producers (wells Nos. 54, 54-66, 64, 55, 55-63, 65, 56-31, 55-66 and 65-36), four pairs of injectors (one injection well in each Upper and Lower Shannon: well pairs No. 55-51 and 55-42, 65-21 and 65-12, 55-55 and 55-45, and 65-25-1 and 65-25) and 10 observations wells (wells Nos. 54-36, 55-41, 55-52, 55-42, 65-22, 55-54, 55-35, 55-46, 65-35 and 65-26). The location of three offset wells closest to the pilot are also indicated in Fig. 3.

Figure 3 reflects the final pilot configuration. Early in the life of the operation, only one injection well penetrating both Shannon intervals was used in each pattern. Unsatisfactory injection profile and ignition failures led to a decision to drill twin injectors such that each pattern contained one injector for the Upper Shannon and another injector for the Lower Shannon.

Well Completion

The wells (both injectors and producers) were equipped with 5-1/2-in., 15-5 lb/ft K-55 casing. In all wells, the casing was cemented to the surface using material and techniques that are standard in thermal recovery projects. The injection wells were perforated in the appropriate bench at a density of four shots per foot. After the injection wells were completed, air injectivity tests were made to determine the injectivity index of each well. Schematic of a typical injection well is shown in Fig. 4.

The production wells were selectively perforated at a density of two shots per foot across the entire pay. During the course of the project (mid-1984), the producers in the pilot area were hydraulically fractured to improve capture efficiency and minimize migration of oil outside the pattern. Conventional beam pump units were installed and 2-7/8-in. EUE tubing was run to the base of the pay zone. Production was carried out by pumping through hollow sucker rods. The annulus between rods and tubing was used for pumping quench water to cool the pump (see Fig. 5).

The observation wells were drilled and cased in the same manner as other wells. Type K thermocouples were run inside casing to monitor the temperature of the formation at various depths. The location of the observation wells were determined based upon pulse testing results and strategically located to gain maximum information about the burning front.

Surface Facilities

Unlike the in situ combustion projects discussed in the literature, the NPR-3 used several different schemes to obtain and sustain ignition. These included electric heater ignition, gas heater ignition and steam preheat ignition. In addition, an enriched air injection scheme was utilized in the mid-1984 as an alternative way to sustain combustion. Consequently, the NPR-3 in situ combustion pilot surface facilities included air compressors, gas compressors, oxygen/nitrogen cryogenic plant, portable steam generator, portable quench water system, and the produced fluid gathering and treatment facilities.

The air injection system consisted of two skid-mounted air compressors and pipelines for delivering air to injection wells. The compressor was a gas engine-driven, five-stage reciprocating compressor, designed to deliver 3,000 Mcf/d was at 1,000 psig discharge pressure. The air for injection delivered through 2-in. injection lines from the air compressor to individual wells. Orifice meters were installed at the wellhead to meter the air injection rate.

The oxygen/nitrogen cryogenic plant was leased from Air Products and included the cryogenic vessels, reciprocating pumps, vaporizers, gas storage vessels and associated metering and control equipment. Air Products operated the facilities and provided support services.

IGNITION

Initial Ignition Attempt

Initial ignition was started on December 6, 1981, with an electric downhole heater in the NE pattern injection well. As noted previously, these early injection wells were drilled and completed in both zones. The plan was to ignite the Lower Shannon first and then move to the upper zone. The heater was lowered to the top of the lower zone perforation and the igniter turned on, while injecting air (12,000 scf/hr) through the 2-7/8-in. tubing. The igniter failed to ignite the formation because of insufficient air flow into the lower zone as indicated by spinner and tracer logs. As most of the injected air went into the high-permeability Upper Shannon, a decision was made to ignite the top zone. Accordingly, the heater was moved up to the top of the Upper Shannon and the igniter turned on January 10, 1982. The ignition attempt was successful as evidenced by the generation of heat in the injection well. After ten days of igniter operations, the temperature profile indicated increased heat in the reservoir. After igniting the first well, the heater was retrieved and attempts were made to ignite the second injector. However, the ignition attempts failed due to mechanical problems with the heater. The heater failed at the connection, and then the coils burned out on spare. Thus, initial ignition attempts resulted in the ignition of a single well. Even though there were signs of limited ignition, the combustion was not sustained as evident by the analysis of gas from surrounding producers and the lack of temperature response in nearby observation wells. Thus, it was concluded that ignition using the electric heater was unsuccessful and the operation discontinued.

Second Ignition Attempt

Analysis of initial ignition attempt results (tracer log data and injection well BHT) suggested that the attempt probably failed because of low reservoir temperature and adverse injection profile. Thus, upon the recommendation of the consultant, a decision was made in May 1982 to drill twin injectors where each pattern contained one injector for Upper Shannon and one injector for the Lower Shannon and to use gas heaters to ignite the formation.

It was believed that gas ignition would elevate reservoir temperature and sustain combustion upon ignition. In the gas ignition process, air and natural gas are injected down casing and tubing, respectively, and mixed in a heat shield which is hung on the end of the tubing. A pyrophoric chemical is used to ignite the gas stream downhole, inside the heat shield. The result is a torch that is set above the perforations and conducts heat through the convection of hot gases.

In July 1982, four new injection wells (55-42, 55-55, 65-21 and 65-25) were drilled and completed in the Upper Shannon. Gas ignition was initiated on July 20, 1982, on well 55-42. Approximately 10.8 MM Btu of heat was generated through the ignition period during the four days of operation. The feed rate to the igniter was 200 scf/min of air and 7 scf/min natural gas. The ignition attempt proved to be successful as evidenced by the rise in casing-seat temperature and a drop in oxygen level in the nearby producer. Encouraged by the success, other injection wells were also ignited and the observation wells monitored. Three months of monitoring gave no indication of sustained combustion as evidenced by the lack of temperature response in nearby observation wells, and high oxygen content (greater than 15%) in the produced gas. The air injection was terminated in December 1982 when it became clear that combustion could not be sustained.

Analysis of the collected data (observation well temperature data) indicated that the ignition attempt probably failed because of insufficient heat injection. Based on theoretical calculation, the minimum heat input required to sustain the combustion was estimated to be 0.5 MM Btu/ft of pay thickness.[6] This value was arrived at based on ignition temperature of 610° F and an oil heat capacity of 0.65 Btu/lb-°F. The average heat injection in the pilot was 10.8 MM Btu (see Table 3) and the average perforated interval was 41.5 ft. This calculates an average heat injection of less than 0.3 MM Btu/ft of pay thickness. If it is assumed that 40% of the injected heat was lost down the fracture, the actual heat injection was 0.18 MM Btu/ft of pay thickness, which is well below the minimum recommended value.

Third Ignition Attempt

Failure of previous ignition attempts to sustain combustion in the Shannon prompted the investigation of alternative ways to assure ignition and propagation of fire front in the Shannon. Laboratory combustion tube runs were performed in early 1983 to determine the best way to ignite the formation and sustain combustion. Runs were made at reservoir temperatures using Shannon crude and rock. After ignition, the first run failed to sustain combustion. It was realized that the sandpack was too cold to sustain combustion. In later runs, the combustion was sustained by elevating the sandpack temperature and/or injecting enriched air. These results indicated that ignition could be achieved and combustion sustained by preheating a portion of the reservoir or by increasing the oxygen concentration of the injected air. A decision was made in March 1983 to field test both these concepts. The pilot area was split into two halves—a northern pattern and a southern pattern, each consisting of two 2.5 acres inverted 5-spot patterns. The preheat concept was tested in the southern pattern and the enriched air process in the northern half.

Southern Pattern

One alternative to enhance the combustion condition is to elevate the reservoir temperature prior to ignition attempt. The objective here was to heat the formation around the vicinity of injection wellbore to a temperature sufficient to support combustion. A steam slug injection program was adopted in lieu of gas ignition for preheating the reservoir. Analysis of the two previous ignition processes indicated that gas ignition, though less expensive, is also less effective and more problem prone. Gas ignition was tried previously in the pilot, but the ignition attempt failed due to poor heat transfer and wellbore damage. During the earlier gas ignition attempt, the casing strings at injection wells 65-25, 65-21, and 55-42 were buckled in the process of igniting the wells.

The steam preheat phase involves elevating the reservoir temperature with steam prior to air injection. Steam was injected into two 2.5-acre, 5-spot patterns from July 15, 1983, to February 15, 1984. The objective here was to heat approximately a 100-ft radius around the injection well to about 220° F prior to ignition. Steam injection was terminated after sufficient heat was put into the reservoir.

Each injector was then resaturated with 80 bbl of highly reactive linseed oil, using the hot oil truck. The injection wellhead configuration for steam preheat/linseed oil injection is shown in Fig. 6. The linseed oil injection was followed by 12 hours of steam injection to elevate the temperature of the linseed oil. This was done to prevent damage to wellbore from reverse combustion of linseed oil. A total of 63,952 MM Btu or 385.3 MM Btu/ft of pay was injected into the reservoir. The cumulative heat injection for both steam preheat and gas ignition in the four injection wells are shown in Table 3. During the steam preheating, oil and water production increased in and around the pilot area, and observation well temperature increased. The steam preheat oil and water productions are shown in Fig. 7.

Following the steam preheat phase, hot air was injected into the formation to ignite the volatile fluids in the reservoir. The hot air (>200° F) was obtained by diverting air from the final compression stage cooler. Spontaneous ignition occurred upon injection of the hot air and the combustion sustained as evidenced by observation well temperatures and produced gas analysis. The air injection was continued until April 1986 at which time the project was terminated in favor of steamflood. The pilot performance and test pilot evaluation are discussed in later sections.

Northern Pattern

Combustion tube tests indicated enriched air could be utilized in lieu of preheating the reservoir to sustain combustion. Consequently, a one pattern test (northwest quadrant) was performed to investigate the concept.

An oxygen/nitrogen plant was leased from the oxygen supplier to provide enriched air for the project. The plant consisted of two cryogenic vessels, pumps, vaporizers, gas storage unit, and associated metering and control equipment.

Oxygen and nitrogen were delivered to cryogenic vessels. Liquid oxygen and nitrogen were drawn from these vessels and pumped through vaporizers to gas storage. The desired injection volumes were drawn from the storage and mixed prior to injection. Separate lines for pure nitrogen and oxygen/nitrogen mixtures were connected to the injection well.

Prior to the commencement of the synthetic air injection test, a nitrogen tracer test was performed to evaluate the likelihood of early breakthrough of oxygen, possibly as a result of fracture jobs performed on the production wells 55 and 54-66. These tests indicated early breakthrough was unlikely and no significant increase in communication between injectors and producers occurred as a result of the fracture job.

At the conclusion of the tracer test, the two injection wells in the pattern (wells 55-42 and 55-51) were saturated with linseed oil (approximately 80 bbl each) to a radius of 6.7 ft. After the linseed oil presoak, a 20%/80% mixture of oxygen/nitrogen was injected beginning August 15, 1984, and step-wise oxygen enrichment began shortly thereafter. The oxygen concentration was then slowly brought up to 40%.

No positive response was seen in either observation well temperature or in produced gas analysis from surrounding wells. It was concluded that ignition was not achieved and the pilot test was terminated in March 1985. Postmortem coring confirmed the absence of combustion in this area of the pilot.

PILOT PERFORMANCE

Unlike the enriched air combustion, the steam preheat/air injection pilot was successful and produced approximately 10,700 bbl of oil from the south half of the pilot pattern.

The pilot evaluation initially centered around monitoring the following basic parameters:

1. Observation well temperature profiles.
2. Produced gas analysis.
3. Exhaust gas and liquid production.
4. Air injection rate and cumulative volume injected.
5. Production volume (gas, water, and oil).

As an example, the Shannon fireflood injection and produced injectant volumes over the duration of the project are summarized in Tables 4 and 5.

Although temperatures over 500° F were measured in two observation wells and the carbon dioxide concentrations in the exhaust gases from certain production wells were high, all monitored parameters indicated an inefficient burn. Only 24% of the pattern was burned (see Table 7). However, it was difficult to determine reasons for inefficiencies due to fluid interactions between patterns and off-pilot migration of injected air, as well as combustion gases and produced fluids. Production wells in the Shannon reservoir were completed in both Upper and Lower Shannon intervals, causing commingling of produced gases and liquid. This further complicated the evaluation of the pilot performance. Figure 8 indicates the extent of off-pilot migration of oxygen measured in March 1985. Over 33% of the produced gases were produced in one well south of the pilot area, labeled 56 on Fig. 8 (also, see Table 4 and Fig. 3) indicating channeling due to fractures. Additionally, production responses were noted in wells up to three rows from the pilot area.

The original Shannon geologic characterization assumed no geologic discontinuities within the NPR-3 boundary and no trends to porosity and permeability variations exist. Faults and fractures were known to be present, but no attempt was made to assess their effect on the production history of the reservoir. The pilot results indicated that the initial reservoir and geologic characterization of Shannon were too simplistic and a better model was required to explain actual performance. It was concluded that the areas that required further investigative work to help explain pilot performance were vertical heterogeneity, fracture/fault influences, reservoir parameters (mainly porosity, permeability, and oil saturation) for the various facies making up the vertical heterogeneities, and performance of the combustion process as it relates to each of the facies present.

Geologic Reinterpretation

To better explain the Shannon combustion pilot performance, the geology of Shannon was reinterpreted in mid-1985. The reinterpretation took two forms. First, a geological model of the Shannon was constructed based on the represented facies. Facies identifications were made utilizing and modifying the Tillman and Martinsen facies model for offshore marine sandbars such as the Shannon.[4] The geological description of the Shannon given earlier was based on this updated geological model. The second direction the reinterpretation took was to examine the effects of faulting and fracturing. Based on the updated geologic interpretation, the following conclusions were drawn:[4]

1. The lower Shannon has essentially no potential for oil displacement based on the facies description within the pilot area (i.e., permeability too low).

2. Only the top 20 ft of the Upper Shannon has sufficient continuity of sand, porosity, and permeability to qualify as a potential floodable reservoir.

3. Faults/fractures have from the initiation of the project influenced the fluid flow. The breakthrough of the injected air in a west-northwest and north-south direction as observed in the pilot areas correspond to the fracture orientation.

The above conclusions were not initially accepted because the ramification implied a drastically reduced resource base amenable to fireflood. Consequently, postburn core analysis, injection rate variation tests and off-pilot production analysis were performed to help aid in the interpretation of the pilot results as well as to substantiate the geologic model.

Postburn Core Analyses

In order to confirm actual combustion performance, nine core wells were drilled and logged in mid-1985. The results of the program solidified many prior opinions as well as dismantled others.

Of the nine core holes, one was drilled between upper and lower injectors in the northwest quadrant or the oxygen/nitrogen project area. The remaining eight cores were retrieved from the two south quadrants.

No combustion was observed in the core taken from the northwest quadrant (Core No. 1). The eight cores taken from the southern pattern showed combustion as noted in Fig. 9. Cores from the southeast quadrant showed combustion in an interval 10 to 15 ft thick in the Upper Shannon (see table 6), confirmed by clean sand (no oil saturation), and increased porosity and permeability due to clay alteration. This interval corresponds to the bar margin facies of the two south patterns. Good correlation existed between core analysis and log interpretation for the burned zone, as shown in Fig. 10.

Visual observation of the core taken from the core well C4 in the southeast pattern showed both the good and bad points of this fireflood. Another core taken from the core well C9 in the southwest pattern clearly showed the effect of heat on oil displacement. Both the cores contained natural fracture. The clean burned portion of the core C4 showed that 100% of the oil in place could be either combusted or displaced, but only the top 15 ft of the core would sustain combustion. The core C4 also showed that the combustion front had propagated until it reached the fracture, but failed to advance beyond the fracture. The fracture acted as a permeability barrier to the movement of the front. The displaced oil drained into the fracture.

Though no burned zone was noted in the core obtained from well C9, the fracture was saturated with oil indicating drainage of displaced oil from the matrix into the fracture. This suggested at least some of the oil produced from the off-pattern wells might have come from the pilot area.

Combustion in the Lower Shannon was associated only with fractures in core taken near injection wells (core wells C2 and C3). Although cores indicated distinct flow direction, combustion front expansion was essentially radial. The overall burning ranged from near radial in the southwest pattern to an oblong shape in the southeast pattern as evident from Fig. 9. Based on burned thickness isopach map (Fig. 9) it was concluded that the greater the distance the combustion front moves away from the injector, the harder it will be to maintain a radial sweep. The average burned radius in the pilot area was estimated from the core analysis to be 106 ft (see Table 6).

The performance evaluation for the period March 1984 to June 1985 is detailed in Table 7. In theory, 10,762 bbl of oil were to be produced from this portion of the pilot. However, the actual volume of the oil produced from this area was much higher than the predicted value. A combination of processes made the evaluation of the pilot performance difficult. They included (1) steam preheating followed by air injection, (2) O_2/N_2 injection, and (3) fracture stimulation of producers. It is uncertain to what extent each process contributed to the production. Based on oil production, it was surmised that steam preheat followed by an air injection process was the singularly greatest contributor to production.

Temperature responses associated with actual pilot combustion front were observed in several observation wells and in one core well (Well C9). These, together with post-core results, were utilized to calculate the burn rate (shown in Table 8). The wide disparity in the calculated burn rate indicates that the sweep is not radial. This, however, contradicts the post-core analysis observation which suggests radial advance. To reconcile this difference, it was concluded that the frontal advance rates were different for each stringer.

Post-core burn analysis facilitated the understanding of what portions of the reservoir were actually being affected. Because of this improved understanding of pilot performance, air injection into the Lower Shannon was discontinued, and the Upper Shannon performance was evaluated through an injection rate variation performance test.

Injection Rate Variation Test

Prior to the coring program, air injection averaged 400 Mcf/D into both the Upper and Lower Shannon through four injection wells. These rates were based on the first geologic interpretations. The updated characterization study demonstrated the floodable sand ($\phi = 0.18$, $k = 63$ mD, $S_o = 0.4$) between 300 ft and 320 ft, a net height of 20 ft which is one-half the floodable sand thickness used for original design. Combustion tube tests had identified the fuel content for the Shannon to be 1.5 to 2.6 lbs/ft^3. This range of values together with the ϕS_o value of 0.1 (0.20 x 0.5) for the bar margin indicated that the air requirement to displace oil would be high (i.e., 15 to 30 Mcf/bbl at 100% oxygen utilization efficiency).

In order to narrow the air-oil ratio (AOR) range, injection rates were varied and produced gases monitored. The objective was to fine tune the pilot by defining the oxygen utilization and fuel content values within the bar margin for the Upper Shannon injectors. The typical well responses are shown in Fig. 11. From this study, the fuel content in the bar margin facies of the Upper Shannon was determined to be 1.67 lb/ft^3, and oxygen utilization efficiency was found to be 55% to 75%. Based on these redefined values, the injection AOR range was reduced to 24 Mcf/bbl at 100% oxygen utilization. This equated to an injection rate range of 32 to 44 Mcf/bbl at oxygen utilization values of 0.75 and 0.55, respectively. Much of the inefficiency was attributed to the divergence of air into fractures and possibly to rock not being able to sustain combustion.

When injection in the Lower Shannon was terminated and injection rates in the Upper Shannon were reduced by 50%, the produced AOR dropped from 24 Mcf/bbl to under 10 Mcf/bbl. These results are also shown in Fig. 12. The reduction in the air injection rate did not affect the oil production as shown in Fig. 13.

The nine producing wells in the pilot area, along with other off-pilot wells, produced the equivalent of 83% of the injected air during the period 1984–86. The remaining 17% was unaccounted for and presumably fingered through fractures into wells not tested for oxygen.

PRODUCTION PERFORMANCE

Oil production from the nine producing wells in the in situ combustion pilot area is shown in Fig. 13. Because of inherent problems associated with small pilot projects within the much larger target reservoir, off-pilot migration is a monumental problem to analyze. An example of the latter case is well 85-5-3, which is located two rows outside of the pilot area. Its production performance (Fig. 14) shows a marked increase concurrent with the in situ combustion pilot operations. Natural fractures and large pressure differentials (i.e., reservoir pressure averaging 60 psia while injecting air at 300 psia) increasingly compounded the evaluation problem. From June 1983 to December 1985, the oil production from the pilot wells and the first row of producers surrounding the pilot exceeded 72,500 STB.[6] Only 17,100 STB was produced from the nine pilot wells. Consequently, any analysis of production performance must include off-pilot production.

Off-Pilot Analysis

To assess the performance of off-pilot producers, the acreage around the fireflood pilot area was broken into nine areas. These areas include the following:

1. Fireflood Group—nine fireflood producers (four old wells and five new wells).
2. Area 1—The first row of producers surrounding the pilot.
3. Area 2—The second row of producers surrounding the pilot.
4. Area 3—All wells in Section 3 except fireflood group, Area 1, Area 2, and Area 9.
5. Area 4—Northern most rows of producers in Section 10.
6. Area 5—Four producers in the northwest corner of Section 11.
7. Area 6—Two most westerly columns of producers in Section 2.
8. Area 7—Southern most rows of producers in Section 35.
9. Area 8—Southern most rows of producers in Section 34.

10. Area 9—7 producers in the Southern portion of Section 3 associated with steamflood.

The off-pilot production response boundary is shown in Fig. 15. Positive production response (increased oil production) was noted within all areas identified above. The closest area to the injectors, the fireflood group, exhibited the greatest production response. The trend of decreasing response was noted as the distance from the injectors lengthen. Enhanced production response was also noted in isolated wells outside the assessment area. The effect of channeling of fluids through fractures was thought to be the cause. A noticeable drop in production from the wells in Area 9 was observed in 1985. This corresponded to the time when air injection was drastically reduced prior to the coring program.

It is not clear whether the off-pilot production response truly represent secondary oil (incremental) production by repressurization or simply an accelerated production that would have eventually been produced by primary means.

Immediate Pilot Production Performance

The immediate pilot area includes the nine fireflood producers in the pilot area (see Fig. 2). These producers showed incremental oil production. However, as noted earlier, modifications made during the pilot life made it extremely difficult to evaluate the production response. A marked increase in production was noted in the five new wells (wells 54-66, 55-63, 56-31, 55-66 and 65-36) over the 1983–84 time frame, but since that time production has been steadily decreasing. Among the older wells, only well 55 showed significant response and that was after hydraulic fracture stimulation of the induced fracture has significantly opened the wellbore to fluid flow. The oil production jumped from 4 bbl/d before fracturing to 40 bbl/d after fracturing. After stimulation, a direct pressure link was noted between well 55 and the injection well in the southwest pattern.

The improved production in well 55 after well stimulation was thought to have resulted from any or a combination of the following:

1. Hydraulic fracture had broken down the formation damage around the wellbore and tapped into the oil bank created by the combustion process.

2. Stimulation fractured the sealing fault located between well 55 and the air injection wells.

In general, the pilot producers exhibited subtle, but obvious production response. Fracture stimulation greatly increased production. In other words, the combustion process appeared to displace oil, but it required stimulation to capture it.

DISCUSSION

Implementation and operation of a pilot project is a task often faced with trepidation, and rightly so. The possibility of serious problems or failure of the pilot process is very real. Experience has demonstrated that even when the process behaves relatively well, several unexpected problems can plague a pilot project. Without a team of operating personnel, oriented towards problem solving, and managers willing to accept innovative solutions, even a well conceived pilot can end up on a list of deemed failures.

Typically, problems are encountered at every stage of a pilot project, and the NPR-3 in situ combustion pilot was no exception. It is to the credit of the pilot operating personnel and consultants that every problem encountered at the pilot were successfully addressed.

The most serious problem encountered at the NPR-3 in situ combustion pilot was ignition. The first two ignition attempts were failures. In the second attempt, several strings of casing were damaged during gas ignition. Failure to conduct combustion tube runs prior to the initiation of the project contributed to the ignition failures. Subsequent combustion tube tests revealed that preheating the reservoir prior to ignition might solve the problem. Failure of the enriched air combustion process can be attributed to the lack of sufficient heat in the formation to initiate auto ignition of the linseed oil. The process might have succeeded, had a hot wire been used for ignition. Failure to characterize the reservoir early on resulted in poor site selection and inefficient burning. Reinterpretation of the reservoir geology permitted a reduction in produced AOR and improved operation. Faults and fractures dominated the flow of injected and produced fluids. Off-pattern wells exhibited better production response than the pilot wells.

The in situ combustion at NPR-3 was initiated and carried through at a time of rising oil prices. This made the project marginally economical in spite of low overall recovery. Under current economic conditions, the project might not be viable. Although the 1985 economic appraisal of the pilot was favorable, the postcore analysis data and other performance indicators led management to conclude that the risk associated with an enlarged operation was too high, and the test was terminated. Projects such as the NPR-3 in situ combustion pilot, however, are necessary to tackle and solve many operational and reservoir-related problems that crop up in any innovative EOR scheme. Better equipment and innovative solutions that often result from such experimental projects usually find widespread application.

Lessons Learned From NPR-3 Combustion Pilot

The most important factor that must be considered prior to undertaking a combustion process in a geologically complex heterogeneous reservoir is to make certain that the reservoir is adequately characterized, and geology well understood. Low matrix permeability, natural fracture network, fault orientation and rock mineralogy can greatly influence the project performance and economics of the operation. Production performance and levels of oil recovery are likely to be less than those predicted with numerical models due to complex flow behavior in fractured reservoirs.

More work is required to gather and evaluate information pertinent to modeling geologically complex reservoirs such as the Teapot Dome field. Data gathered from the combustion projects conducted in complex reservoirs such as the NPR-3 can go a long way in modeling combustion process in geologically complex reservoirs.

Projects such as NPR-3 combustion pilot can provide an opportunity to experiment with performance and process design. The better and even encouraging production trends in some wells provide an opportunity to formulate and explain mechanism of recovery under certain settings.

CONCLUSION

In summary, the following conclusions are drawn.

1. The geologic characterization study and the results of the in situ combustion pilot indicated that only within the bar margin facies of the Shannon sandstone at Teapot Dome can a displacement process be successfully applied.

2. Faulting and fracturing throughout the reservoir were found to dominate the flow of injected and produced fluids. The postburn coring data indicated that natural fractures will sometimes act as a barrier and stop the advancement of the combustion front.

3. Overall sweep efficiency ranged from near radial in the southwest pattern to an oblong shape in the southeast pattern.

4. Off-pilot producers showed better production response than the pilot producers.

5. No major operational problems other than ignition failures were encountered during the life of the project.

6. Final oil saturation in the burned sand was 0%. All of the oil originally present in the burned volume was either displaced or burned.

7. Seventeen thousand one hundred barrels of oil or 23% of the OOIP in the pilot area was produced at an air-oil ratio of 39.2 Mcf/bbl.

ACKNOWLEDGMENTS

The first two authors (Sarathi and Olsen) wish to express their appreciation to the NPR-3 field staff for their support and cooperation. The authors wish to thank the U.S. DOE for their support and permission to publish this paper.

REFERENCES

1. Grooms, G. E. and R. K. Schulte: "Contribution of Observation Well Logging to the Evaluation of Polymer-Augmented Waterflood Pilots," presented at the 60th Ann. Tech. Conf., and Exhib. of the Soc. of Pet. Eng., Las Vegas, NV, Sept. 22-25, 1985. Paper SPE 14396.
2. Martinsen, R. S. and R. W. Tillman: "The Shannon Shelf Ridge Complex, Salt Creek Anticline Area, Power River Basin, Wyoming," SEPM Special Publication No. 34, Tulsa, OK, pp. 85-142.
3. Porter, K.W.: "Stratigraphic Model for the Upper Cretaceous (Campanian) Hygiene Member, Pierre Shale, West Denver Basin, Colorado," Ph.D. Dissertation, Colorado School of Mines, 1976.
4. Obernyer, S. L.: "Geologic Evaluation of the Shannon Sandstone, Teapot Dome Field, NPR-3, Natrona County, Wyoming," Consultant (SURTEK)," Report to U.S. DOE, February 1986.
5. Chappelle, H. H., G. P. Emsurak and S. L. Obernyer: "Screening and Evaluation of Enhanced Oil Recovery at Teapot Dome in the Shannon Sandstone: A Shallow Heterogeneous Light Oil Reservoir," presented at the SPE/DOE Fifth Symp. on Enhanced Oil Recovery, Tulsa, OK, Apr. 20-23, 1986. Paper SPE/DOE 14918.
6. Surkalo, H. and R. B. Yeats: "In Situ Combustion Pilot Production and Reservoir Performance Evaluation, Teapot Dome Field, NPR-3, Natorana County, Wyoming," Consultant (SURTEK) Report to U.S. DOE, Nov. 15, 1985.

TABLE 1

Petrophysical Properties of Shannon NPR-3

Layer	Net Thickness, ft	Porosity %	Horizontal Permeability mD	Vertical Permeability mD	Initial Water Saturation %
Upper Shannon:					
Bar margin	10	26.0	200.0	2.0	45.0
Interbar	6	22.5	20.0	0.4	50.0
Bioturbated shelf	32	18.0	3.0	0.05	66.0
Lower Shannon:					
Interbar	3	24.0	45.0	0.05	48.0
Bioturbated shelf	22	16.0	0.5	0.0	70.0

TABLE 2

In Situ Combustion Performance Calculation Shannon Reservoir, NPR-3

	2.5-Acre	
	Case (1)	Case (2)
Fuel deposition, lb/ft^3	1.0	1.0
Unit air requirement, Scf/ft^3 of formation	180	180
Fuel consumption per ac-ft of the reservoir rock, lb/ac-ft	43,560	43,560
Air injected per ac-ft, MMScf	7.8	7.8
Air injected per ac-ft of the 5-spot pattern to breakthrough, MMScf	4.9	4.9
Total air required for the 5-spot pattern, MMScf	982	442
Air flux, Scf/ft^2-day	22.5	22.5
Maximum daily air injection rate for the pattern, MMScf/day	2.0	0.9
Time required to reach the maximum daily injection rate, days	88	88
Volume of air injected while reaching maximum daily injection rate, MMScf	88	40
Volume of air during constant rate period, MMScf	806	362
Duration of constant rate, days	403	402
Total time required to complete the operation, days	579	578
Maximum air injection pressure, assuming no stimulation, psig	897	897
Maximum air injection pressure, assuming stimulation with skin factor is equal to –3	674	674
Oil displaced from the reservoir burned, bbl/ac-ft	496	496
Oil displaced from unburned reservoir, bbl/ac-ft	248	248
Total oil recovery, bbl/ac-ft	322	322
Overall recovery efficiency, % OOIP	52	52
Oil recovery per MMScf of air injected, bbl/MMScf	66	66
Air oil ratio, MScf/bbl oil	13.3	13.3
Maximum theoretical oil production rate from the 5-spot pattern, bbl/day	132	59
Total water produced, bbl/ac-ft	412	412
Water produced per MMScf of air injected, bbl/MMScf	84	84
Maximum theoretical water production rate from the 5-spot pattern, bbl/day	168	76

Case 1: 100% of net sand thickness swept by injected air - theoretical maximum.

Case 2: 45% of net sand thickness swept by injected air - probable vertical sweep.

TABLE 3

Cumulative Heat Injection for Steam Preheat and Gas Ignition

Injection Well	Steam Preheat, MMBTU	Gas Heating, MMBTU	Perforated Interval, ft
55-45	13,315.9	10.7	31
55-55	18,380.6	10.3	42
65-25	17,799.5	10.4	51
65-25	12,600.0	11.8	42
Average Values	15,524.0	10.8	41.5
Linseed Oil Heat Input	1,856.0	0.0	
Total Average Heat Input	15,988.0 or 385.3 MMBTU/ft net pay	10.8	

The heat generated from combustion of linseed oil = 80 bbl/well X 5.8 MMBtu/bbl = 464.0 MMBtu/well.

TABLE 4

Injection/Produced Injectant Summary

Fireflood
- Air Injection Commenced 1/82
- Air Injection Ceased 4/86
- Note that several intermittent time periods exist with no injection.

	1980	1981	1982	1983	1984	1985	1986	Total
Total Air Injection (MScf)	0	0	508,000	390,000	447,000	397,000	35,000	1,777,000
Total Steam Injection (BW,CWE)	0	0	0	122,979	53,199	0	0	176,178

Production (MScf) - Exhaust Gas as reported for the following wells only.

Well No.								
54	--	--	49,689.9	58,536.0	22,151.4	24,815.7	6,489.0	161,682.0
55	--	--	12,876.6	11,526.6	19,472.0	14,108.1	2,401.5	60,384.8
56-31	--	--	5,807.8	6,333.9	8,688.5	4,179.9	697.5	25,707.6
54-66	--	--	16,889.8	24,003.8	20,290.7	27,428.6	4,884.0	93,496.9
55-63	--	--	22,323.3	29,226.9	35,838.5	62,168.1	5,489.5	155,046.3
55-66	--	--	25,304.5	49,574.3	48,454.2	37,201.5	4,363.8	164,898.3
64	--	--	18,435.7	24,793.6	5,465.7	3,448.1	657.5	52,800.6
65	--	--	49,000.7	50,892.7	10,525.8	12,362.4	1,079.5	123,861.1
65-36	--	--	16,684.8	12,819.3	5,995.1	4,094.2	471.0	40,064.4
(off-pilot wells)								
44	--	--	--	6,891.1 (9 Mo.)	5,785.8 (9 Mo.)	7,839.4	2,029.0	22,545.3
45	--	--	--	8,262.2 (9 Mo.)	19,352.0 (9 Mo.)	18,975.7	2,220.0	48,809.9
56	--	--	--	5,879.9 (9 Mo.)	80,460.5 (9 Mo.)	109,661.0	4,414.3	200,415.7
TOTAL	--	--	217,013.1	288,740.3	282,480.2	326,282.7	35,196.6	1,149,712.9

NOTES:
1. 1986 Exhaust Gas Production reported over the period 1-1/86 through 8-31-86.
2. Exhaust Gas Production is known to have been produced from other wells via oxygen surveys but was not measured. Therefore, produced injectant quantity is conservative.

TABLE 5

Produced Water Summary

	1980	1981	1982	1983	1984	1985	1986	Total
Production (BW) - Water production as reported for the following wells only.								
Well No.								
54	--	--	--	406	429	140	44	1,019
55	--	--	--	130	496	152	45	823
56-31	--	--	--	363	5,225	817	112	6,517
54-66	--	--	--	279	225	44	0	548
55-63	--	--	--	1,406	3,610	532	123	5,671
55-66	--	--	--	3,170	10,072	962	155	14,359
64	--	--	--	217	863	124	6	1,210
65	--	--	--	1,586	2,222	282	133	4,223
65-36	--	--	--	1,720	2,097	427	263	4,507
(off-pilot wells)								
44	--	--	--	29	426	794	99	1,348
45 "	--	--	--	83	827	93	235	738
56 "	--	--	--	68	110	300	213	691
TOTAL	--	--	--	9,457	26,102	4,667	1,456	41,682

NOTES:
1. Produced water reported above commences 8/83.

TABLE 6

Postmortem Core Results

	Net burned zone, ft									Average H, ft	Burned volume, ft	Est. burn radius, ft
Core Well	C1	C2	C3	C4	C5	C6	C7	C8	C9			
SW Pattern	NA	15			11	10	8		[1]0	11	410,000	109
SE Pattern	NA		11	11				9		10.3	340,000	103
Avg. for Pilot										10.7	375,000	106

[1] Burn front had not arrived at C9 at the time of coring, but from the measured temperature, the burn front was inferred to be near.

TABLE 7

Pilot Performance Evaluation for the Southern Half

	SW Pattern	SE Pattern
Area, acres	2.96	2.51
Thickness, ft	12.6	14.0
Porosity, %	23.1	21.4
Acre-ft	37.3	35.1
Pore Volume, bbl	66,838	58,340
Oil saturation, %	50.00	50.0
Oil form. volume form., BO/RB	1.01	1.01
Oil in place, RB	33,088	28,881
Pore volume burned,[1] bbl	16,600	13,700
Percent of total pattern burned, %	24.8	23.5
Fuel burned,[2] bbl	2,258	1,873
Total OIP, burned zone, bbl	8,206 bbl (33,088 X .248)	6,787
Displaced Oil, bbl	5,948 (8206-2258	4,814

1 Mainly bar margin (may be some inter bar).

2 SW Pattern

Fuel Burned $= \text{Burn Volume}(\text{ft}^3) \text{ X Fuel Content} \frac{(\text{LBS})}{\text{ft}^3}$

$= 410{,}000 \text{ ft}^3 \text{ X } 1.67 \frac{\text{LBS}}{\text{ft}^3} = 684{,}700 \text{ LBS}$

$684{,}700 \text{ LBS X } \frac{\text{Ft}^3}{54 \text{ LBS}} \text{ X } \frac{\text{BBL}}{5.615 \text{ Ft}^3} = 2{,}258 \text{ BBLS}$

SE Pattern

Fuel Burned $= 340{,}000 \text{ Ft}^3 \text{ X } 1.67 \frac{\text{LBS}}{\text{Ft}^3} = 567{,}800 \text{ LBS}$

$567{,}800 \text{ LBS X } \frac{\text{Ft}^3}{54 \text{ LBS}} \text{ X } \frac{\text{BBL}}{5.6.5 \text{ Ft}^3} = 1{,}873 \text{ BBLS}$

TABLE 8

Burn Rate Estimation from Observation Wells Data

Observation well No.	Inject. well No.	Distance between wells, ft	Ignition date	Date of response	Days to response	Inject. Area, ft^2	Inject. rate Scf/hr	Air Flux rate Scf/hr-ft^2	Actual burn rate, ft/d
65-26	65-25	87	1/18/84	5/15/84	118	5,849	12,367	2.11	0.73
55-46	55-55	92	2/01/84	5/28/84	117	6,185	12,575	1.52	0.79
55-64	55-55	91	2/01/84	7/23/85	539	6,118	13,053	2.53	0.17

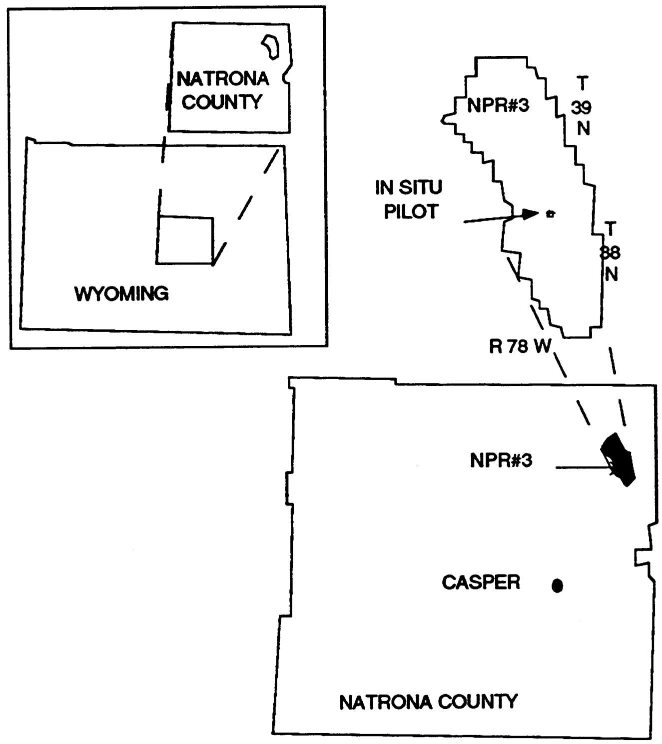


Fig. 1 NPR-3 location map.

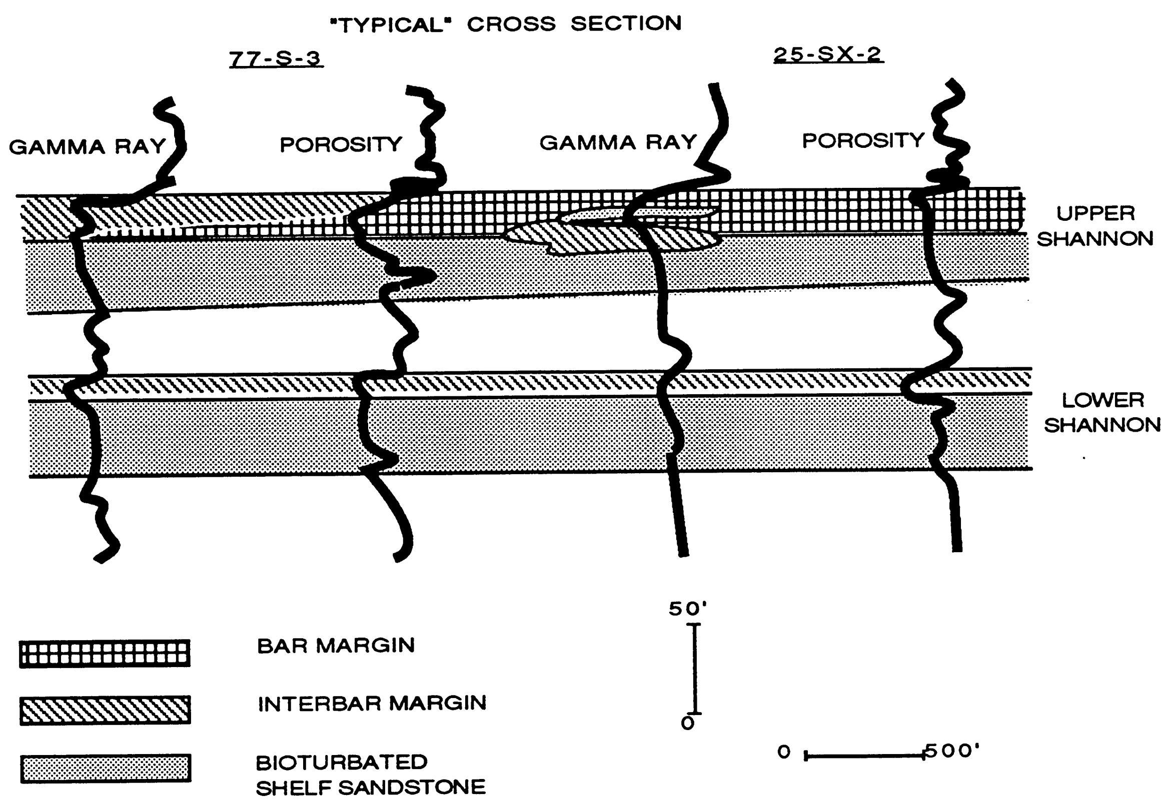


Fig. 2. Facies/Log description identifying Shannon's depositional environment.

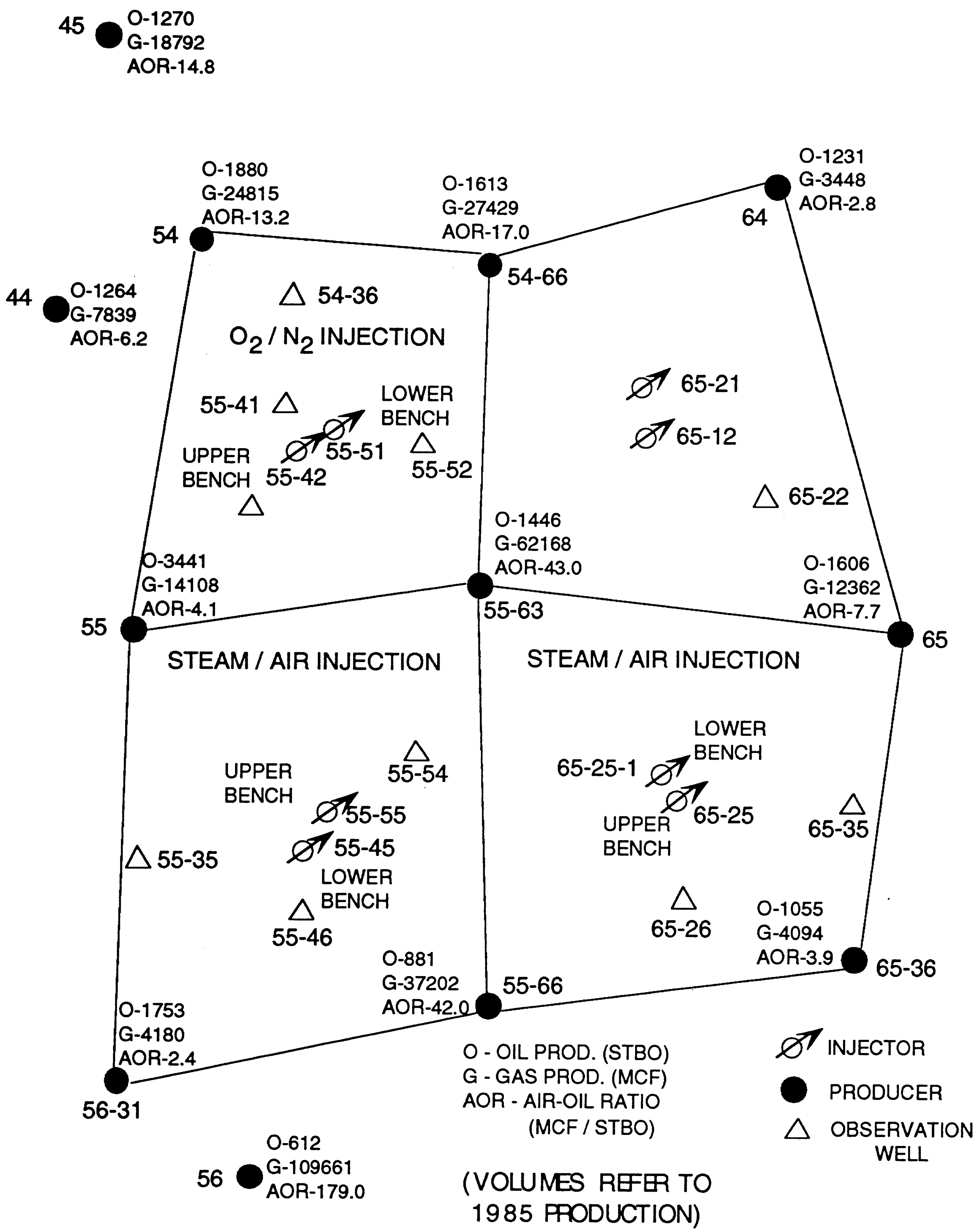


Fig. 3 NPR-3 in situ combustion pilot layout.

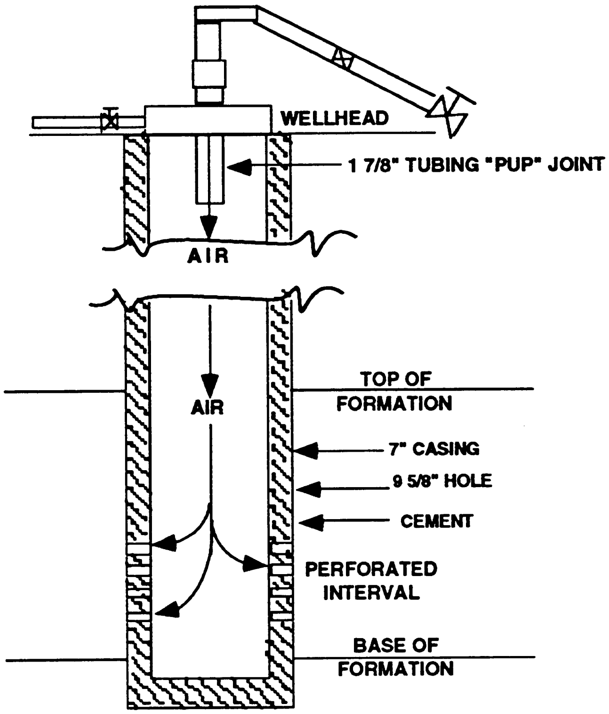


Fig. 4 Schematic of typical in situ pilot air injection well

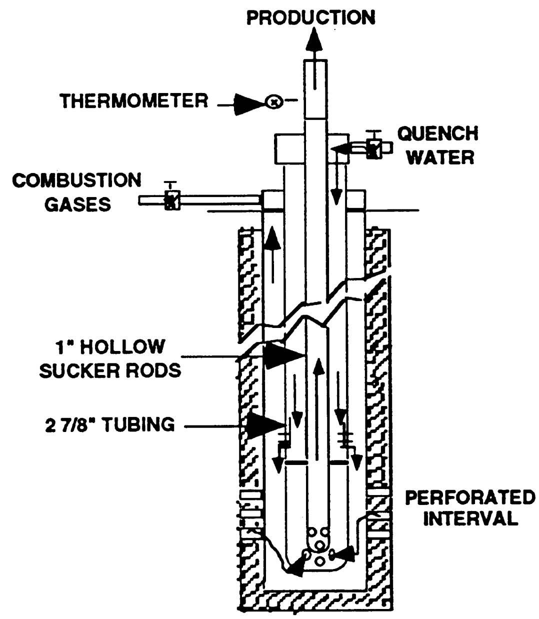


Fig. 5 Schematic of a typical in situ pilot production well.

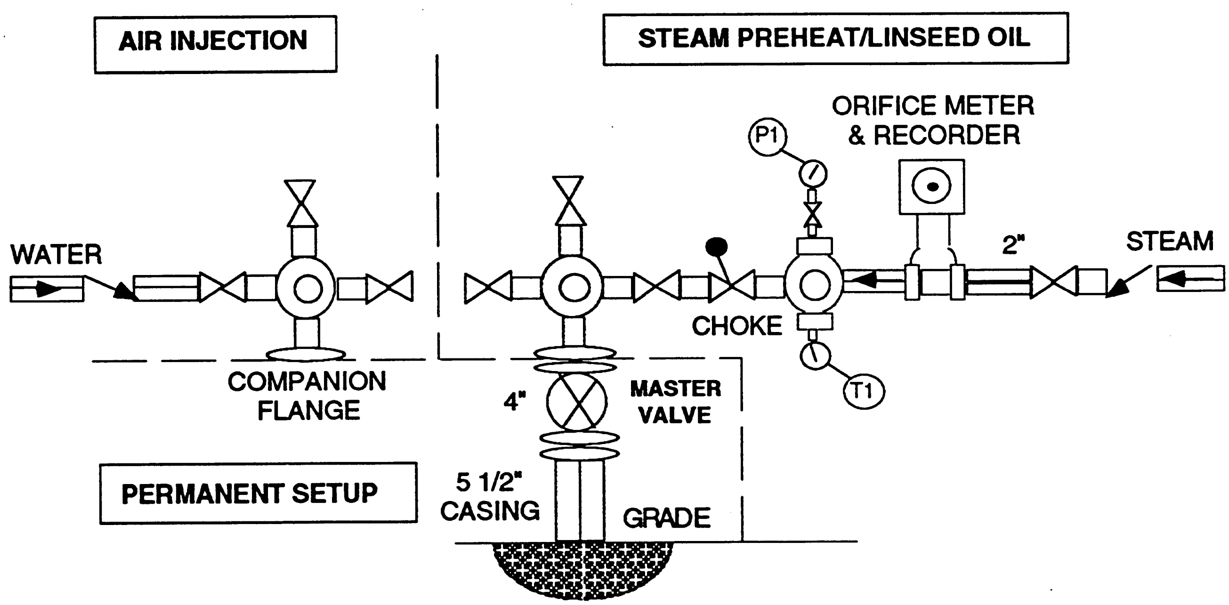


Fig. 6. Schematic of fireflood injection wellhead configuration for steam preheat/air injection.

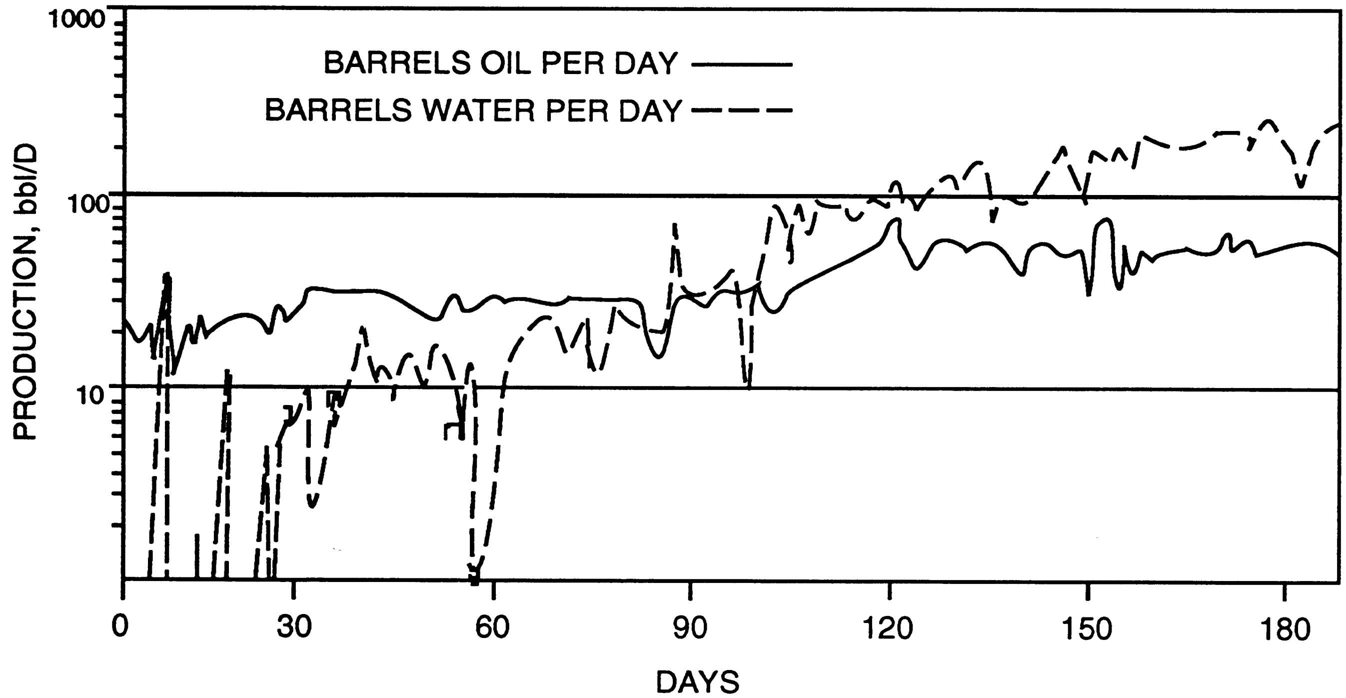


Fig. 7 Production of oil and water due to steam preheat prior to in situ combustion.

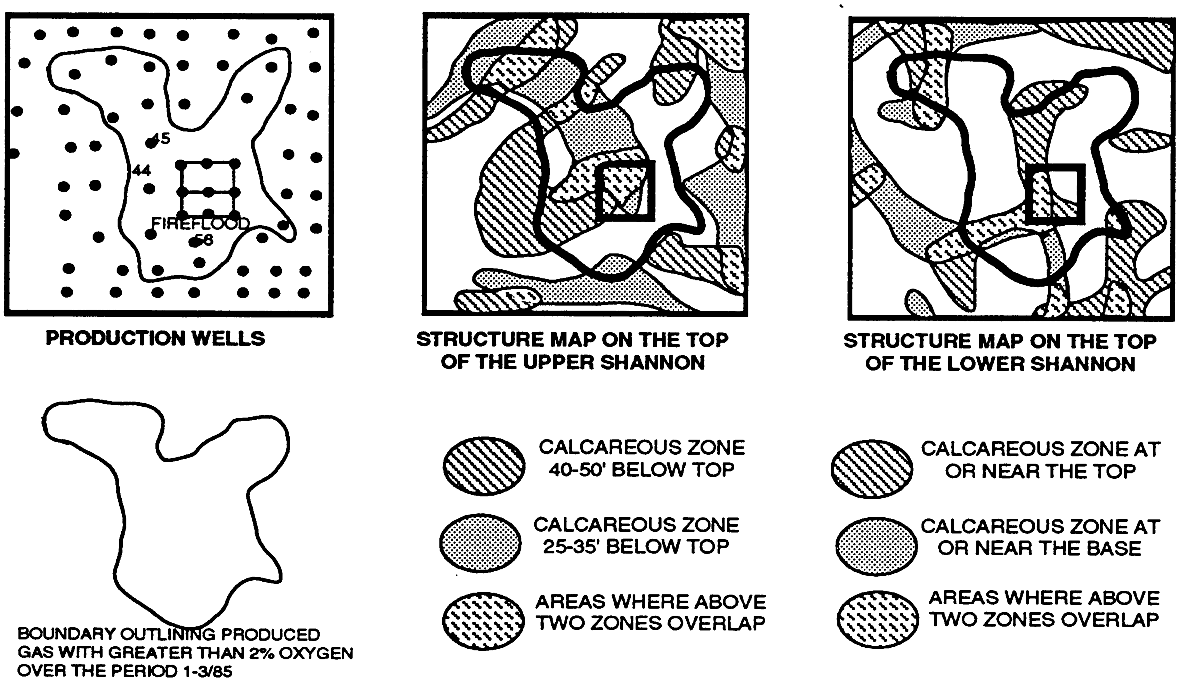


Fig. 8. NPR-3 fireflood—extend of off-pilot oxygen migration as of March 1985.

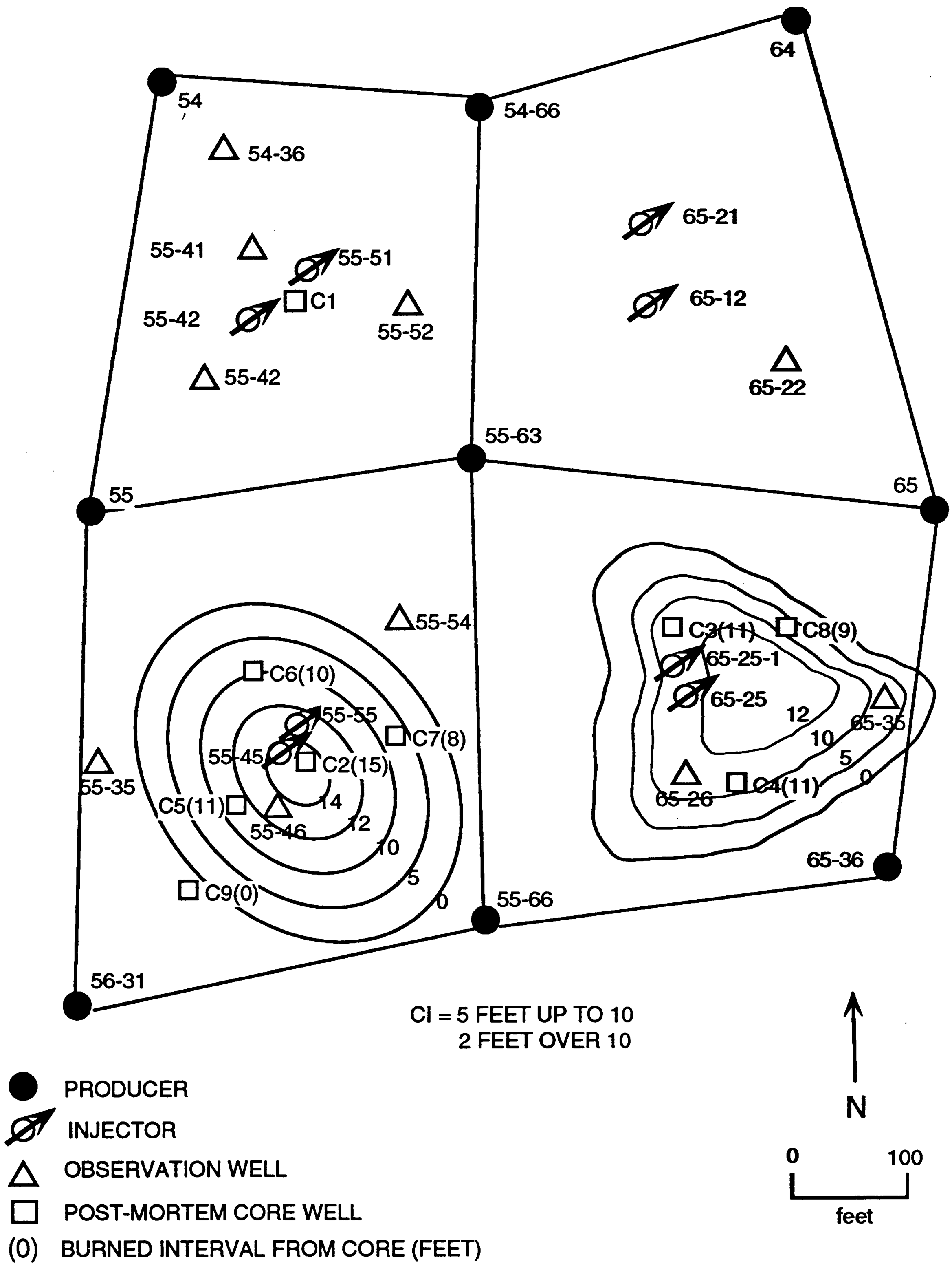


Fig. 9 NPR-3 fireflood burned volume isopach from cores.

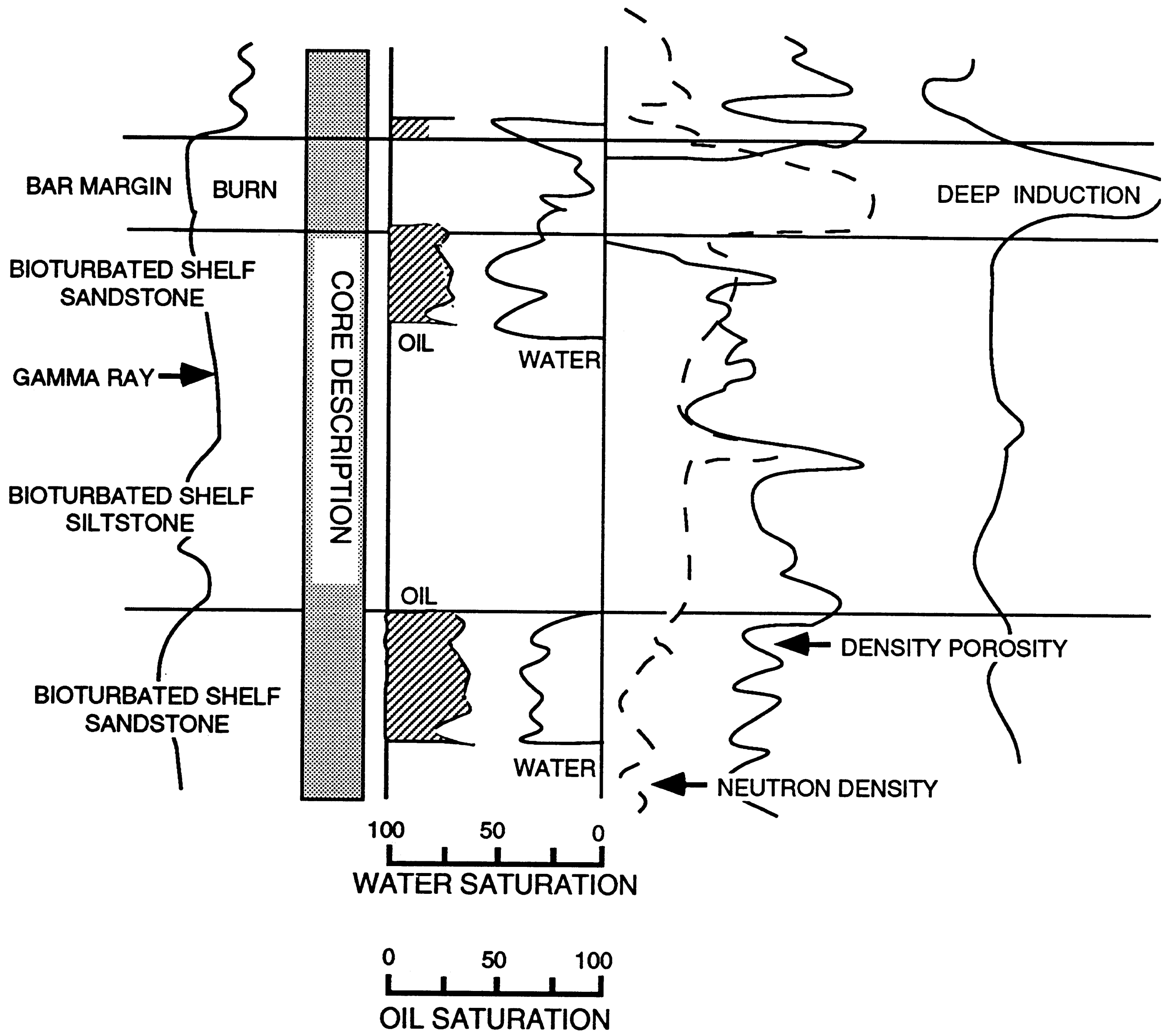


Fig. 10. Core-log correlation in burned interval.

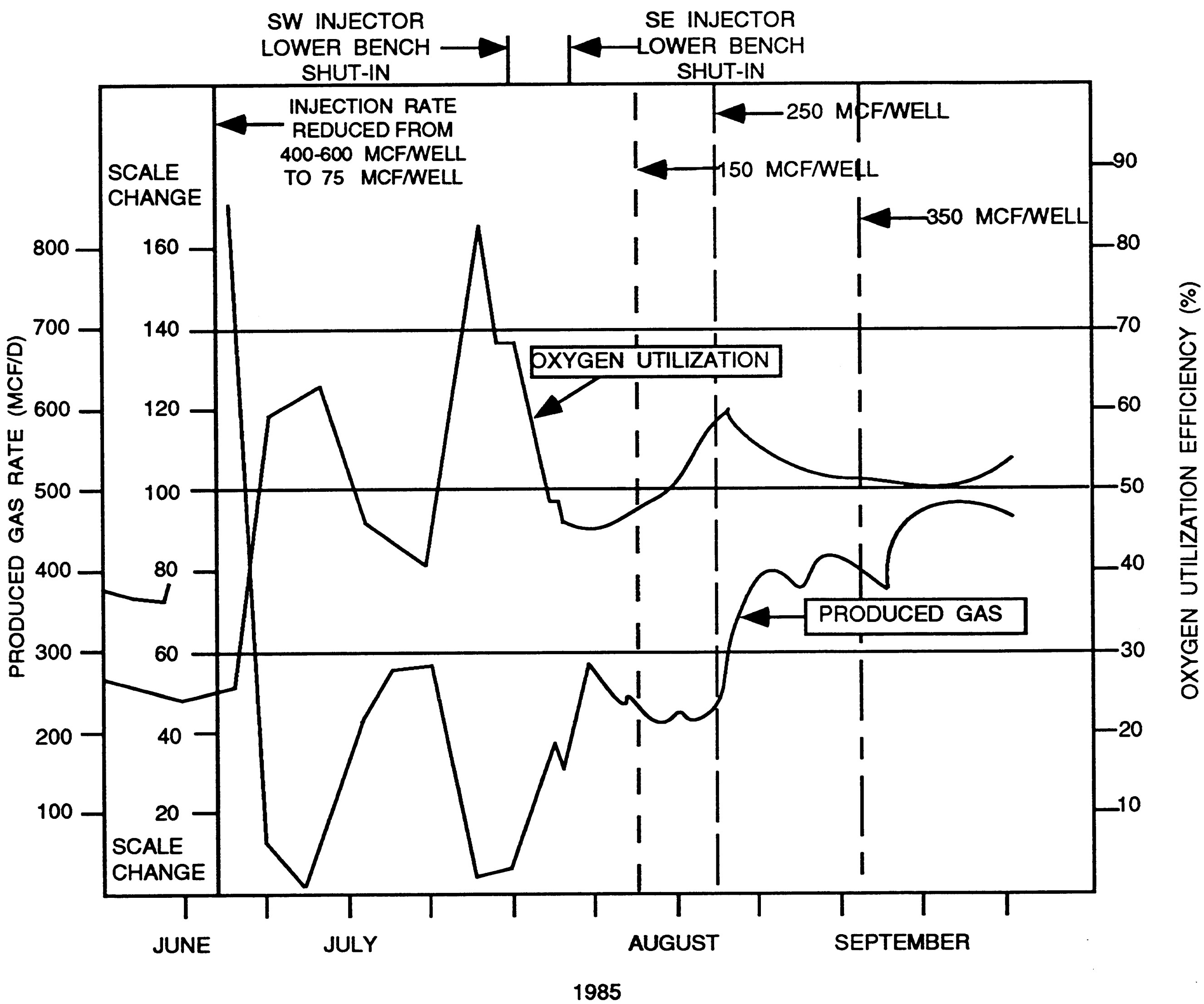


Fig. 11. **Injection rate optimization results in a typical well.**

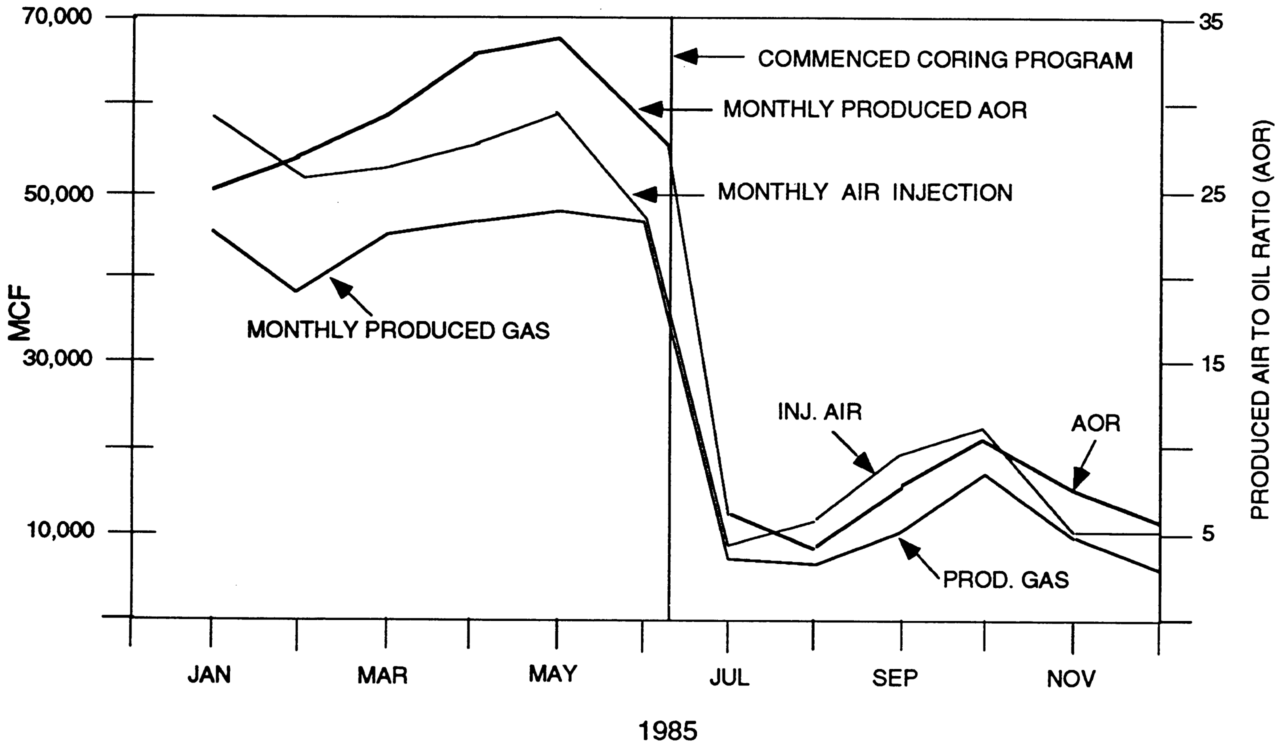


Fig. 12. Monthly air injection, produced gas and AOR.

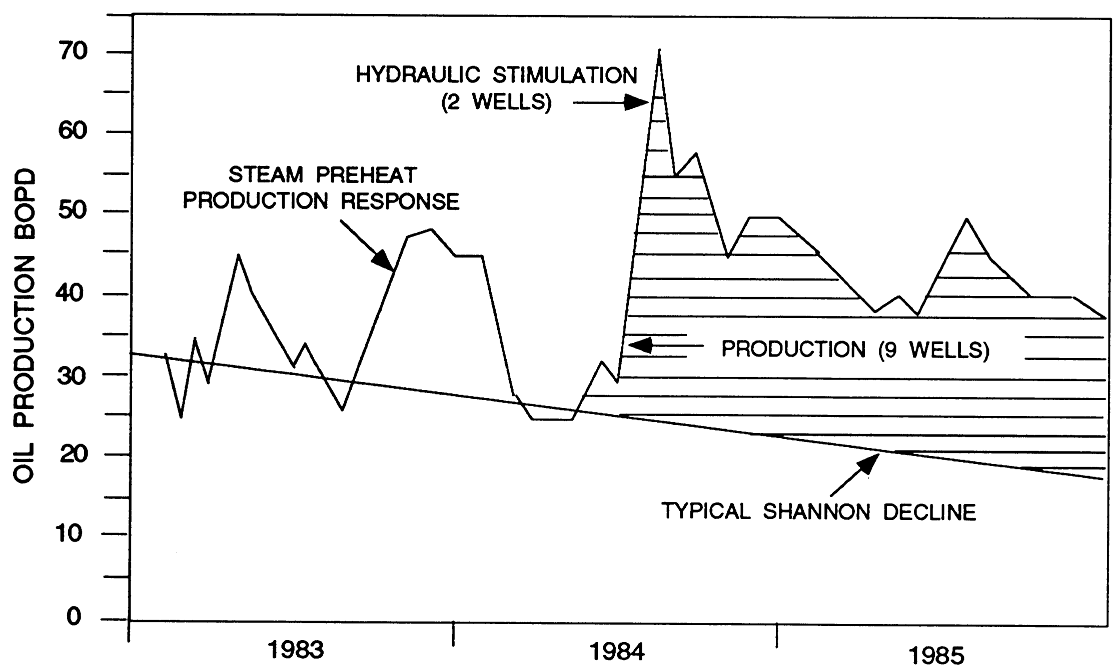


Fig. 13. In situ combustion oil production.

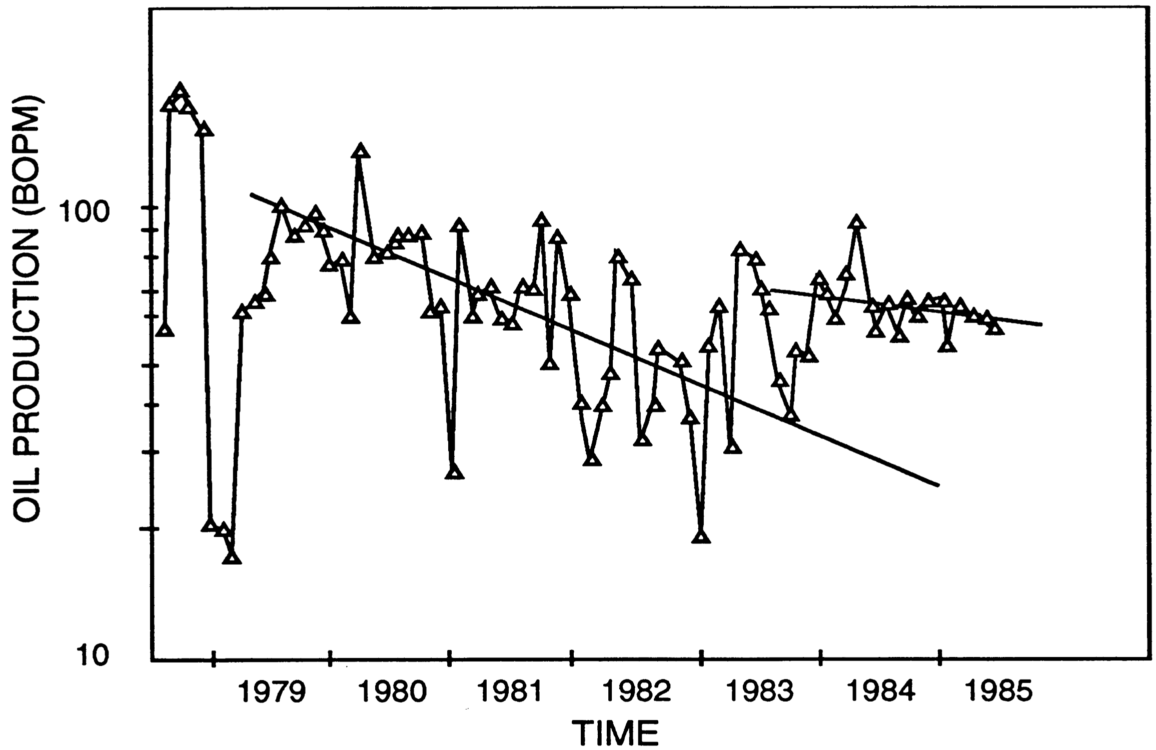


Fig. 14. Off-pilot oil production to in situ combustion in well 85-5-3.

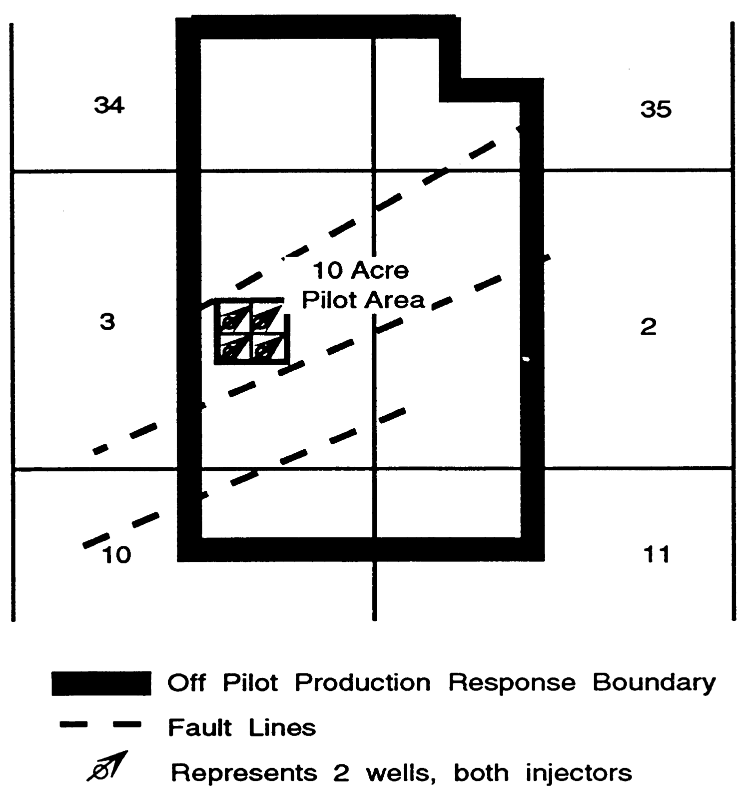


Fig. 15. NPR-3 Fireflood—Area around the pilot exhibiting positive production response.

No. ISC 14 DOE/NIPER

Enhanced Oil Recovery Using Hydrogen Peroxide Injection

by J. T. Moss, Jr. and Jon T. Moss, Tejas Petroleum Engineers, Inc.

This paper was prepared for presentation at the DOE/NIPER, Symposium on In Situ Combustion Practices—Past, Present and Future Application in Tulsa, Oklahoma, April 21-22, 1994.

This paper was selected for presentation by a Program Committee following review of information contained in an abstract submitted by the author(s). The material, as presented, does not necessarily reflect any position of the U.S. Department of Energy or the National Institute for Petroleum and Energy Research.

ABSTRACT

NOVATEC received an U.S. Patent[1] on a novel method to recovery viscous oil by hydrogen peroxide injection. The process appears to offer several significant improvements over existing thermal methods of oil recovery. Tejas joined NOVATEC to test the process in the laboratory and to develop oil field applications and procedures.

BASIC CONCEPTS OF HYDROGEN PEROXIDE PROCESS

The physical properties of hydrogen peroxide (H_2O_2) indicate that H_2O_2 injection has the potential of combining the more favorable aspects of many EOR processes: namely, (1) steam, (2) combustion, (3) oxygen-water combustion, and (4) carbon dioxide injection. Hydrogen peroxide decomposes to form water and oxygen (O_2). Both products are environmentally desirable and effective in recovering oil.

Heat is generated in the oil reservoir when the decomposition reaction occurs. Additional heat is generated when the oxygen formed by hydrogen peroxide decomposition reacts with residual oil. This combustion reaction generates gases with a high carbon dioxide (CO_2) content. The available heat from the reactions support steam and hot water at equilibrium conditions. Continued injection of liquid H_2O_2 advances the heat bank, steam zone, hot water zone, oxygen burning front, and the CO_2 bank through the formation, effectively displacing oil.

References and illustrations at end of paper.

The physical characteristics of H_2O_2 are ideally suited for thermal EOR in either shallow or deep oil fields. The liquid specific gravity is 1.45 and its viscosity is 1.25 cP at 20° C. It can be hauled by trucks and pumped by conventional oil field equipment. The design of the injection system seems highly simplified when compared to steam or combustion projects, although handling and safety procedures must be adapted to oil field conditions.

LABORATORY INVESTIGATION OF HYDROGEN PEROXIDE PROCESS

As the injected liquid contacts the oil zone, H_2O_2 decomposes to water and oxygen and liberates heat.

$$2H_2O_2 \rightarrow 2H_2O + O_2 + \text{Heat}$$

The released O_2 then reacts with residual oil to form a burning front, similar to combustion projects.

Preliminary laboratory studies were conducted to evaluate H_2O_2 injection as an oil recovery process. First, the laboratory tube was packed with clean sand, about 15% water saturation, but no oil. Temperatures increased showing that considerable heat was generated when H_2O_2 decomposes to water and oxygen.

To evaluate burning, 21% oil and 21% water saturated sandpack was used. Figure 1 shows the pack temperatures at thermocouples 1 to 10 (2-inch spacing). Pack temperatures reached 820° F at the burning front. A steam plateau at 400-420° F was observed behind and ahead of the burning zone. Carbon dioxide reached 80% even though nitrogen had been injected as a safety precaution.

These results are encouraging but more studies are needed to fully evaluate the process and to develop procedures for oil field application.

HYDROGEN PEROXIDE AS A THERMAL OIL RECOVERY PROCESS

Figure 2 shows the H_2O_2 specific gravity and water of reaction for various concentrations of H_2O_2 expressed as weight percent according to industry practice. Water is a product of the decomposition reaction. Figure 2 shows about 0.78 bbl water per bbl H_2O_2 (100%) results from the reaction. The oxygen generated by H_2O_2 decomposition is significant. Figure 3 shows about 2,830 Scf O_2 per bbl H_2O_2 (100%) is formed by H_2O_2 decomposition.

Considerable heat is released when H_2O_2 decomposes. Figure 4 shows the heat generated for various H_2O_2 concentrations. One hundred Percent H_2O_2 releases 1,240 BTU/lb. Even more heat is generated in the reservoir when the oxygen reacts with oil. This is shown by the middle curve on Fig. 4. The upper curve shows the total heat from both decomposition and combustion is about 3,890 BTU/lb (100% H_2O_2). Total heat decreases with H_2O_2 concentration, but Fig. 4 shows that concentrations above 10-15% releases a considerable amount of heat.

Figures 5 and 6 can be used to compare H_2O_2 injection with steam and combustion processes. Figure 6 shows that one barrel H_2O_2 (100%) equals six barrels oil field steam injection. The 50 MMBTU/hr steam generator commonly used for steam projects is equivalent to a pump rate of only about 600 BPD, 100% H_2O_2. The entire steam plant for a fairly large EOR project, along with associated water treating and stack gas equipment, can be replaced with a 2,500 BPD pump.

Combustion projects typically operate at air injection rates of 500 to 1,500 MCFD/well. Figure 5 shows that an injection rate of 75 BPD of 100% H_2O_2 is the oxygen equivalent of 1,000 MCFD air injection. The Cities Service Bodcau project air plant capacity was 20.9 MMCFD, or about 5,000 HP. To illustrate the potential significant reduction in equipment and associated operations, the H_2O_2 process pumps only 1,570 BPD 100% H_2O_2 to inject the same amount of oxygen used in the Bodcau Project.

HYDROGEN PEROXIDE AS A CARBON DIOXIDE OIL RECOVERY PROCESS

The results of the H_2O_2 tests and previous laboratory work using oxygen indicate that the following approximate reaction occurs.

$$128.5\ O_2 + 100\ CH_{1.5} \rightarrow 82\ CO_2 + 18\ CO + 75\ H_2O + \text{Heat}$$

Field projects usually show less CO and higher CO_2 than the above laboratory results. CO_2 concentrations under field conditions may be in the 90-95% range when equilibrium is reached.

Produced gas will also contain varying amounts of hydrocarbons and other reservoir gases which reduces the CO_2 concentration to less than maximum.

From the above reaction, the volume of combustion gases is 78% of the oxygen injected. Obviously, the gas volume is much less than associated with air combustion projects. When compared to a 1,000 MCFD air rate, only 164 MCFD combustion gases are produced.

Gases that move ahead of the heat front, into the oil bank and other sections of the reservoir are rich in carbon dioxide. This is similar to oxygen enriched combustion and is also analogous to CO_2 projects. In heavy oil projects where the contact efficiency of the CO_2 is high, much of the CO_2 will dissolve in the oil. This reduces the oil viscosity by 80-90% and significantly improves oil displacement. Furthermore, the mobility ratio for heavy oils will be shifted in a favorable direction, and project sweep efficiency will be higher.

Produced gases, rich with CO_2, can be re-compressed and injected to enhance oil recovery outside the project area.

In deep, high pressure reservoirs, CO_2 is expected to be even more effective in displacing heavy oils, and for less viscous oils, a miscible CO_2 bank is likely to occur.

HYDROGEN PEROXIDE AS A "HUFF AND PUFF" PROCESS

In oil fields where "Huff and Puff" works, its the best thermal recovery process. The oil/steam ratio is one or higher and heat injection is minimized. More important, increased oil rates are immediate.

When the H_2O_2 process is used for "huff and puff" well stimulation, both heat and CO_2 will reduce oil viscosity near the wellbore, and the CO_2 will form a gas drive when the well is returned to production. Both effects are expected to increase oil recovery when compared to conventional steam stimulation treatments.

No special well completions are needed because the injected H_2O_2 is at normal formation temperatures. The heat is generated in the formation. Most existing wells can be treated and depth does not limit the process.

HYDROGEN PEROXIDE FOR PROJECT IGNITION

Igniting the oil sand is a time consuming and often costly prelude to combustion projects. Sandface ignition requires about one million BTU per foot of zone thickness. For example, a 20 foot oil sand is ignited with 20 MMBTU heat injection. The ignition procedure requires 24 hour surveillance for 5 to 10 days at reasonable injection rates and special ignition equipment.

Using H_2O_2 for ignition requires only 25 barrels 50% H_2O_2 to inject the heat. Time, equipment, and personnel are greatly reduced, and wellbore damage should not occur. A 50% H_2O_2 volume was used in this example because this concentration was used in the laboratory and no particular problems were encountered.

How to ensure good vertical sweep at the injection well must be investigated in the laboratory and field. Varying peroxide concentrations and selective use of decomposition catalysts or inhibitors may control when and where the energy is released in the formation.

SPECIAL APPLICATIONS FOR THE HYDROGEN PEROXIDE PROCESS

Arctic Area

Some reservoirs seem particularly suited for H_2O_2 injection. In Arctic areas such as the North Slope of Alaska, peroxide injection will not disturb the permafrost around injection wells as happens with steam or hot water injection.

Deep Reservoirs

The main limitation for steam injection is that much of the heat is lost before steam reaches the zone of interest, especially in deep formations. H_2O_2 can be injected to any depth with no heat loss to the overburden. H_2O_2 gains heat from the overburden.

Wellbore Treatments

In many cases, oil well productivity is improved by hot oil treatments, solvent flush, etc. Peroxide treatments to generate high temperatures around the wellbore may be more effective in many cases and should be evaluated.

CONCLUSIONS

H_2O_2 injection is potentially superior to other thermal EOR processes. Some of the obvious advantages of H_2O_2 injection are summarized as follows:

1. H_2O_2 is compatible with the environment because it reacts to water and oxygen.
2. A conventional triplex pump replaces steam generators, compressors, and auxiliary equipment.
3. Heat loss from surface lines is eliminated.
4. Downhole heat loss from the injection well is eliminated.
5. Insulated flow lines and tubing are eliminated.
6. The additional cost of competing wells for high temperatures is reduced or eliminated.
7. The process is applicable to both shallow and deep heavy oil reservoirs and to many light oil reservoirs.
8. H_2O_2 contains no inert nitrogen which sometimes causes air combustion projects to finger through the oil zone resulting in premature breakthrough and reduced sweep.
9. The mobility of the injected liquid compares to heavy, more viscous water, which is much more favorable for oil displacement than steam, air, or oxygen.
10. The oil mobility is increased because increased temperature, CO_2 solubility, and vaporized light ends reduce the oil viscosity.
11. The improved mobility promotes higher sweep efficiency than conventional thermal processes.

The H_2O_2 process has substantially all of the advantages of well stimulation and thermal flooding with hot water, steam, or in situ combustion and CO_2 injection. Furthermore, this process potentially overcomes most major drawbacks of conventional thermal recovery methods. Industry support of further development of the H_2O_2 process appears justified.

ACKNOWLEDGMENTS

The work and suggestion of Dr. Bob Williams and Jack Bayless of NOVATEC are greatly appreciated.

REFERENCE

1. Bayless, Jack H. and Williams, Robert E.: "Recovery of Viscous Oil from Geological Reservoirs Using Hydrogen Peroxide," U.S. Patent No. 4,867,238, Sept. 19, 1989.

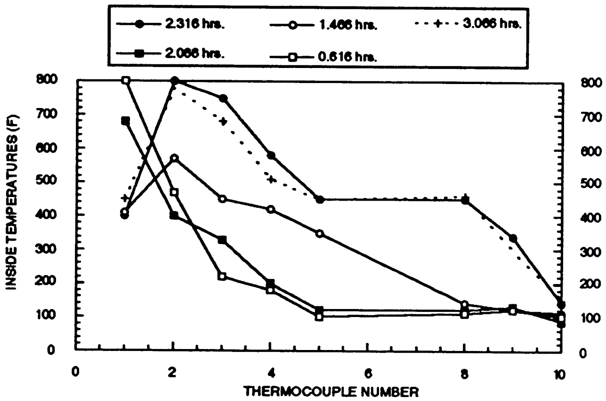


Fig. 1. Sandpack temperature profiles.

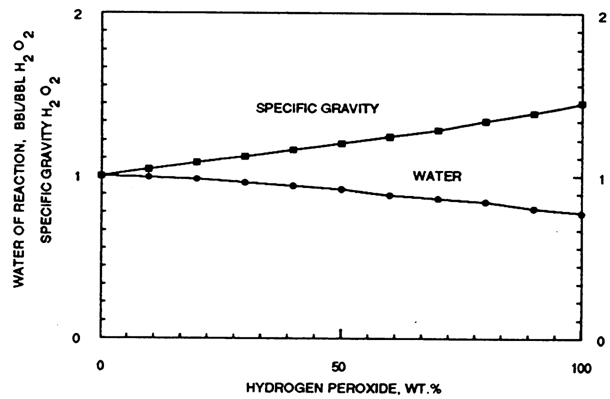


Fig. 2. Specific gravity reaction products of hydrogen peroxide.

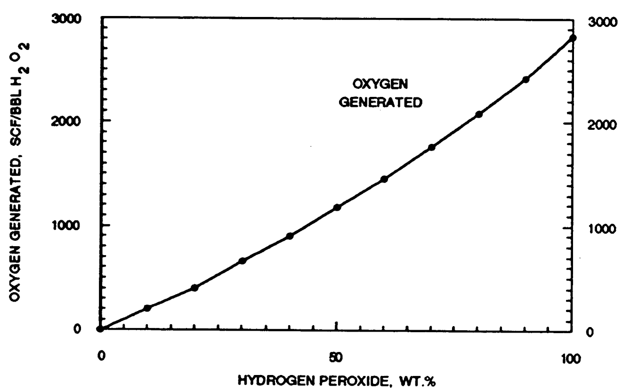


Fig. 3. Oxygen generated reaction products of hydrogen peroxide.

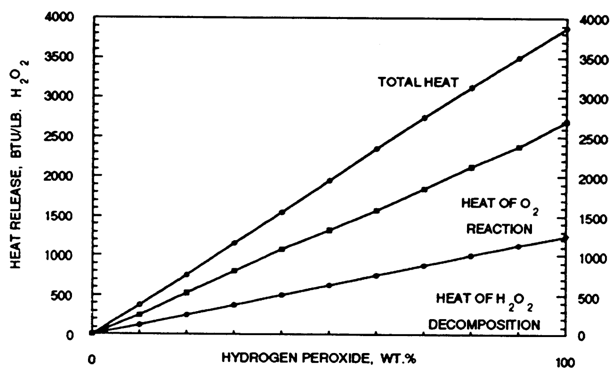


Fig. 4. Heat generated by H_2O_2 injection.

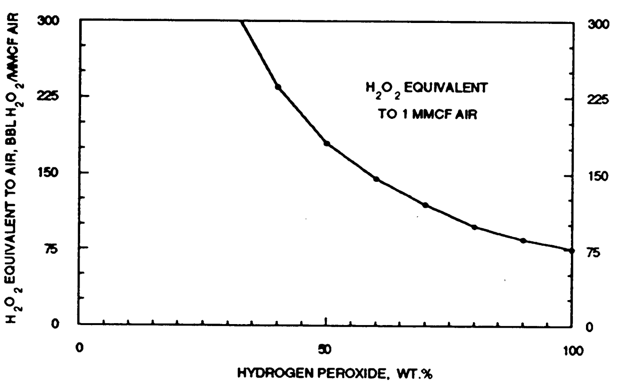


Fig. 5. Equivalent air injection rates for the H_2O_2 process.

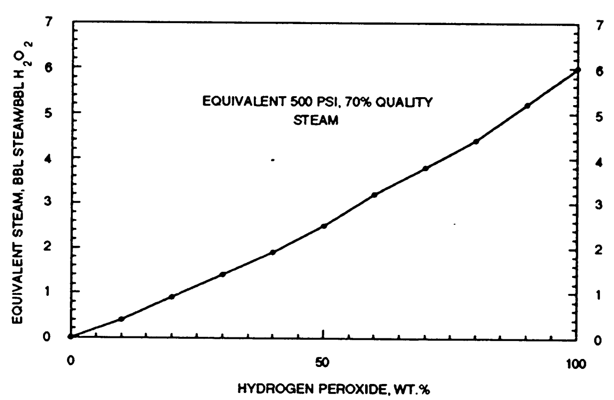


Fig. 6. Equivalent steam injection rates for the H_2O_2 process.

CASE HISTORIES
DISCUSSION

Cochairs: Vinod Kumar, KOCH Exploration
Jesus Bolivar, INTEVEP

Speakers: R. G. Moore, University of Calgary, Calgary, Canada
T. H. Gillham, Amoco Production Co., Houston, TX
B. G. Ames, Mobil Oil Canada, Calgary, Canada
R. Trent, University of Alaska, Fairbanks, Alaska
D. K. Olsen, BDM-Oklahoma, Bartlesville, OK

Paper ISC-9—An Evaluation of the Benefits of Combined Steam and Fireflooding

Question for Gordon Moore from Jeff Weissman, Texaco, Inc., Glenham, New York

Did you observe any changes in the produced oil gravity? If so, did you measure it as a function of different combustion regime or test?

Response by Gordon Moore, University of Calgary, Canada

Yes, the produced oil gravity varied with the type of tests we performed. In all tests we saw an alteration in the produced oil gravity. The degree of alteration, however, depends very much upon the type of test. For example, the alteration is much higher in the steam co-injection test than when steam is followed by combustion.

Paper ISC-10—The Use of Air Injection to Improve the Double Displacement Process

Question for Mr. Gillham from Alex Turta, Petroleum Recovery Institute, Calgary, Canada

This is a classical example of a combination process. In this case, it is a combination of in situ combustion and gravity drainage processes. For this process to be successful, you have to satisfy two opposing requirements simultaneously. To sustain the combustion front, you must have a minimum air flux, which translates into a minimum air injection rate, say, 50 Mscf/D. For the gravity drainage process to be effective, the air injection rate must not exceed certain critical rate, say, 20 MScf/D. Obviously, you cannot satisfy both requirements simultaneously and you have to make a choice. My question is, how did you resolve this dilemma?

Response by T. H. Gillham, Amoco Production Co., Houston, Texas

Raza [M. R. Fassihi], my coauthor, has performed extensive simulation studies on the process and is in a better position to answer your question.

Response by M. R. Fassihi, Amoco Production Research Co., Tulsa, Oklahoma

Your question is well taken. There is no existing injection rate conflict because of the expanding cross section. The cross section increases as you move down dip. We inject air in the attic area at a rate based on the critical rate for gravity stabilized displacement. The initial injection rate is well above the critical rate and sufficient to accommodate the minimum air flux required to sustain combustion. At a certain cross section down dip, the air flow matches the critical rate for gravity stabilized displacement. Based on extensive calculations, we selected an injection rate that satisfied both criteria.

Question for M. R. Fassihi from A. Turta, Petroleum Recovery Institute, Canada

Your plan calls for burning the top one-third of the reservoir and recover oil by gravity drainage from the bottom two-thirds. My question is, why did you choose this approach?

Response by M. R. Fassihi, Amoco Production Research Co., Tulsa, Oklahoma

It is a matter of economics. We expect to reduce the residual oil saturation in bottom two-thirds to 8% by virtue of gravity drainage. You can burn the entire reservoir and recover additional oil, over and above what you can produce by gravity drainage alone. But based on our estimate, the additional incremental recovery is not sufficient to pay for continued air injection costs.

Question for Mr. Gillham from Ron Miller, KOCH Exploration, Wichita, Kansas

What is your injection pressure?

Response by T. H. Gillham, Amoco Production Co., Houston, Texas

We plan to inject air at 4,300 psi.

Question for Mr. Gillham from Ron Miller, Koch Exploration, Wichita, Kansas

How did you decide what the injection pressure should be? Have you performed any model studies to verify the sensitivity of the recovery efficiency to injection pressure?

Response by M. R. Fassihi, Amoco Production Research Co., Tulsa, Oklahoma

Our current plan calls for air injection into two fault blocks FB_2 and FB_4. We plan to inject air at higher pressure into FB_2 and at lower pressure into FB_4, just to investigate the effect of pressure on displacement efficiency. Our simulation results indicate pressure will have some beneficial effect on recovery. The question is whether the additional recovery will pay for the added compression costs?

Question for Mr. Fassihi from Tom Buxton, Consultant, Tulsa, Oklahoma

How did you arrive at the 8% residual oil saturation number for the gravity drained area? Have you done any experimental work to support this conclusion?

Response by Mr. Fassihi, Amoco Production Research Co., Tulsa, Oklahoma

We arrived at this figure based on our experimental work in support of some of our international operations. We have not done any experimental work on this particular field. However, published results on field observation from fields with similar properties to ours, such as the West Hawkins field, indicated the 8% residual is realistic.

Paper ISC-11—Application of Horizontal Well Technology in a Mature Combustion EOR Project: Battrum Field, Saskatchewan, Canada

Question for Mr. Ames from John Belgrave, University of Calgary, Alberta, Canada

Your injection wells are perforated at the top of the sand. Is there any particular reason?

Response by B. G. Ames, Mobil Oil Canada, Calgary, Canada

I am not sure why the wells were completed in that fashion. The only logical explanation I have is that these are producers that were later converted into injectors. Water production is a major problem in this field, and to minimize water production, the producers were perforated near the top. Later, when these wells were converted into injectors, they were not reperforated.

Question for Mr. Ames from Grand Duncan, Petro Canada, Calgary, Canada

What is your injection pressure?

Response by Gene Ostapovich, Mobil Oil Canada, Calgary, Canada

We maintain 1,300 psi at the sandface.

Question for Mr. Ames from Duncan, Petro Canada, Calgary, Canada

How strong is your aquifer? You mentioned that during primary production, your reservoir pressure fell rapidly. This rapid decline in pressure indicates that your aquifer is noninvasive. Can you comment on this rapid decline?

Response by B. G. Ames, Mobil Oil Canada, Calgary, Canada

The structurally high northwest corner of the field was not underlain by mobile water, and it is this portion of the field that experienced rapid pressure decline. In the southern portion of the field, pressure decline was not rapid, and the influx of water from the aquifer into the mobile water zone dominated the pressure maintenance and voidage replacement.

Question for Mr. Ames from Bill Brigham, Stanford University, Stanford, CA

What is the current production rate of the horizontal wells? Are they economical?

Response by B. G. Ames, Mobil Canada, Calgary, Canada

Our first horizontal well currently produces 70 m^3/D and the second well at 20 m^3/D. Though both wells are economical, we feel that the wells must produce at least 40 m^3/D to provide an acceptable rate of return. A reduction in operating cost and lower royalty payment, made this project economically attractive.

Paper ISC-12—Shallow Oil Production Using Horizontal wells With Enhanced Oil Recovery Techniques

Question for Mr. Trent from Gordon Moore, University of Calgary, Canada

What was your injection rate?

Response by R. Trent, University of Alaska, Fairbanks, Alaska

We injected air at the rate of 330 ft^3/min.

Question for Mr. Trent from Gordon Moore, University of Alaska, Fairbanks, Alaska

How did you decide what the injection rate should be?

Response by R. Trent, University of Alaska, Fairbanks, Alaska

We were limited by our compressor output.

Question for Mr. Trent from Gordon Moore, University of Calgary, Canada

What was your formation temperature after ignition?

Response by R. Trent, University of Alaska, Fairbanks, Alaska

We did not measure it, but based on tube runs we estimated it to be around 900° F.

Comment from G. Moore, University of Calgary, Canada

Based on your gas analysis and poor production response, I would say that you were encountering a classic LTO type recovery. I suggest that you core your burn zone and analyze it.

Paper ISC-13—Naval Petroleum Reserve No. 3 (NPR-3), Teapot Dome Field, Wyoming: Case History of the In Situ Combustion Pilot Operation

Paper ISC-14—Enhanced Oil Recovery Using Hydrogen Peroxide Injection

SUMMARY OF PANEL PRESENTATION AND DISCUSSION

As part of the in situ combustion symposium, a five-member panel with expertise in various aspects of in situ combustion technology was convened to discuss the current and past in situ combustion practices and to assess the future of in situ combustion technology. The panel team members are all current practitioners of in situ combustion technology and are acknowledged experts in various facets of in situ combustion technology.

Panel Moderator: David Tiffin, Amoco Production Research

Panel Members: W. Carey Hardy, International Energy Engineering Consultants
Jon T. Moss, Tejas Petroleum Consultants
Gordon Moore, Professor, University of Calgary
Tom Buxton, Consultant
John W. Kirkpatrick, Consultant

The panel presentation and discussion, which lasted for 2-1/2 hours, covered topics ranging from kinetics to novel in situ combustion processes in order to cater the varied interests of the audience. The panel members presentations are summarized in the following paragraphs.

SUMMARY OF PRESENTATION BY W. CAREY HARDY

Mr. Hardy, President of the International Energy Engineering Consultants, Richardson, TX, presented the highlights of five of the 13 in situ combustion projects he was associated with while at Sun Oil Company. The projects overviewed include: Iola fireflood, Allen County, KS; May-Libby In Situ Combustion, Delhi field, LA; Glen Hummell fireflood, Wilson County, TX; Gloriana In Situ Combustion project, Wilson County, TX; and Trix-Liz In Situ Combustion project, Titus County, TX.

The Iola fireflood was a pilot combustion test, conducted in the southwest Moran field in Allen County, KS, in a shallow Bartlesville sand reservoir. The project consisted of two diamond shaped patterns covering areas of 5 acres and 15 acres. The project initiated in April 1965 was terminated in March 1968, after burning 93 ac-ft of reservoir, due to leaks from the reservoir through old unplugged holes which could not be located. The oil recovered from this project amounted to 51,212 bbl of 20.1° API oil compared with 88,238 bbl displaced from the burned zone. The principal problems associated with this project were (1) anisotropic characteristics of the reservoir causing combustion front to move ten times more rapidly in the NE-SW directions than in the opposite directions. The realization of the anisotropy of the reservoir necessitated the realignment of wells in the project area to maximize recovery; (2) the existence of abandoned unplugged wells caused air to leak and forced the project to terminate prematurely; (3) the poor quality of tubingless completion resulted in two well failures. The experience gained from the operation of this in situ combustion experimental work served as the foundation upon which other Sun combustion projects were built.

The May-Libby combustion project was initiated in a thin waterflooded light oil reservoir. The reservoir has an average thickness of 4.4 ft and oil gravity of 40° API. The oil in place at the start of the fireflood was 740 bbl/ac-ft. The initial test was a pilot conducted in a 40-acre area using a inverted five-spot pattern. Over the 3-1/2 years life of the pilot, the project recovered 163,080 bbl oil at a cumulative air oil ratio of 14.26 Mscf/bbl. The primary operational problem in the May-Libby in situ combustion project was corrosion of subsurface and surface equipment and scaling of downhole pumps. The corrosion was combated through a corrosion inhibitor program. A squeeze treatment program using an organic phosphate chemical was employed to minimize scale problem. Other operational problems include production of difficult to treat emulsion and minor sand production. The May-Libby in situ combustion program was both an engineering and economic success and demonstrated that thin, watered-out light reservoirs can be successfully fireflooded.

Sun also successfully implemented firefloods in three Texas heavy oil reservoirs—Glen Hummell and Gloriana fields in Wilson County, TX, and the Trix-Liz field in Titus County. All three projects were economically successful. The oil recovery from the Glen Hummell reservoir, due to fireflood, was 732,000 bbl, which amounted to 56% of OOIP. The oil recovery from Gloriana attributable to fireflood was 1,540,000 bbl, or 57.6% of OOIP. The Trix-Liz fireflood project produced over 3 million bbl of oil. No major or insurmountable operational problems were encountered during the life of these projects. A knowledge of all reservoir characteristic combined with sound engineering planning and project monitoring led to the success of these fireflood projects.

SUMMARY OF PRESENTATION BY TOM BUXTON

Dr. Tom Buxton, who recently retired from Amoco Production Research Company after a distinguished career, discussed the factors that must be considered while evaluating reservoirs for fireflooding. These include reservoir thickness, depth, oil in place, oil gravity, oil mobility, and well spacing. Large well spacing, high permeability, thick net pay, high recoverable oil saturation and good oil mobility favors economic success of the project. Depth, oil gravity, and oil viscosity play only a minor role in the technical success of an in situ combustion project. The screening criteria proposed by various authors reflect the author's bias and the economic conditions prevalent at the time it was proposed. One should not overlook the importance of combustion tube runs and numerical simulation prediction while selecting candidate reservoirs for fireflooding. The most significant reservoir characteristics in failed fireflood projects were: $\o S_o$ less than 0.1, $\o$ less than 0.15 and S_o less than 0.3.

SUMMARY OF PRESENTATION BY GORDON MOORE

Dr. Gordon Moore, Professor and Head of the Department of Chemical and Petroleum Engineering at the University of Calgary, Alberta, Canada, discussed the kinetics of in situ combustion reaction and the insights they provide in the understanding of this complex oil recovery process.

Combustion tube experiments provide temperature histories which are used in the interpretation of combustion performance in relation to the product gas compositions and fluid production rates. The traditional belief is that combustion tube tests always show a propagating high temperature zone which displaces oil towards the production wells and the main function of a combustion tube test is to determine the oxygen and fuel requirement parameters. In fact, one of the most important functions of a combustion tube test is to ascertain the stability of the burning process in a given reservoir.

Studies conducted at the University of Calgary and other places have indicated the occurrence of three main reactions during fireflooding: (1) thermal cracking, (2) low temperature oxidation (LTO), and (3) high temperature oxidation (HTO). Thermal cracking involves cracking reactions (cleavage of carbon-carbon bonds), which result in the formation of lower carbon number molecules and condensation reactions that involve the formation of molecules of greater carbon numbers. While thermal cracking reactions are believed to be the principal means of fuel generation ahead of the combustion zone, they alone cannot describe the fuel laydown mechanisms. For most Canadian oil, thermal cracking occurs only if the operating temperature is in the 200–600° C range. This requires the air flux within the combustion zone to be above some minimum level.

The main reason that field projects deviate from the laboratory prediction is the existence of the low temperature oxidation (LTO) reactions. LTO are oxygen addition reactions, and do not produce CO_2. The products of LTO reactions are organic peroxides, organic acids and aldehydes. Although LTO is generally believed to occur at temperatures below 300° C, it is difficult to assign a temperature range to the LTO region, due to the occurrence of bond cleavage reactions between 150° and 180° C. The LTO reaction is characterized by a decline in oxygen uptake rate in the temperature range of 250° to 300° C. This temperature interval over which the oxygen uptake rate decreases with increase in temperature is designated as the negative temperature gradient region. The negative temperature gradient region has a significant effect on the ultimate success or failure of an in situ combustion process. This is because failure of the oxidation reaction temperature to exceed the upper temperature of the negative temperature gradient region will result in very poor oil mobilization efficiency. The LTO reactions are promoted by low air fluxes in the oxidation zone. The rate of LTO reaction increases with an increase in the oxygen partial pressure of the feed gas.

Ramped temperature oxidation (RTO) tests are performed to determine the oxygen uptake rates under low temperature conditions and to compare the reactivity of different oils. Another finding of the RTO tests is that it is much more difficult to ignite an oil which has been previously oxidized than it is to ignite the original oil. This implies that in the field project the degree of oxidation of the oil should be minimized prior to ignition to avoid ignition failure.

The currently available in situ combustion numerical simulators do not adequately account for low temperature oxidation kinetics and hence are inadequate to predict field performance. Effort expended in the development of a reaction scheme which can predict combustion performance over a wide range would enhance our ability to interpret field performance correctly. Since it is not possible to describe completely all of the reaction mechanisms, a kinetic approach is the only practical way to describe numerically the oxidation-related phenomena.

SUMMARY OF PRESENTATION BY JOHN KIRKPATRICK

Mr. John Kirkpatrick, who consults internationally on thermal EOR-related issues, discussed the problems related to air compressors and downhole igniters.

The air compressor is the most critical of all surface facilities in an in situ combustion project, and care must be exercised in the specification and selection of the compressor to minimize sudden failures. Compressor vendors serving the petroleum industry, unless specified, usually supply compressor suitable for gas compression. Since heat of compression of air is much higher than for natural gas, the piston may seize due to inadequate clearance between piston and cylinder wall resulting from thermal expansion. Purchasing a unit not designed for its intended purpose could result in project delay. The air compression capacity depends on the size of the project being designed. Purchasing a lower capacity unit should be avoided. A standby air compressor is also recommended to ensure uninterrupted air supply in the event of primary compressor failure.

Using synthetic lubricant in compressor cylinder is recommended to eliminate possible explosion within the pressurized system. A hydrocarbon-based lubricant, when mixed with compressed air at high temperature, could lead to a spontaneous combustion explosion. One should avoid installing a flowmeter close to the compressor to eliminate false readings from pressure pulsation. Since compressors function at only about 80% of the rated peak capacity on a continuing basis, specifying an oversized compressor to meet the anticipated injection rate is recommended.

Unless the formation is very hot (reservoir temperature greater than 260° F), it is unlikely that autoignition will occur at the wellbore. Ignition usually occurs at a small distance from the well, and the combustion front moves backward towards the injection well before taking off in the direction of air flow. Unless care is taken, the backflow is likely to damage the wellbore casing.

To avoid this situation, using a downhole burner to initiate ignition under controlled conditions is recommended. In most downhole gas burners, the natural gas is fed through the tubing, and the air is fed down the annulus at an air/gas ratio of 64:1. Only a portion of the air is used to burn the gas, and the rest is used as a coolant to moderate the high temperature generated during the burning. If the air compressor fails during ignition, the extremely high heat from combustion is likely to cause casing damage. To avoid this, cooling water must be circulated through the casing annulus.

SUMMARY OF PRESENTATION BY JON MOSS

Mr. Moss, who consulted and designed numerous in situ combustion projects since 1958, discussed the use of hydrogen peroxide in recovering heavy oil. The hydrogen peroxide process has the potential of combining the more favorable aspects of many EOR processes, such as (1) steam, (2) in situ combustion, and (3) carbon dioxide injection, while avoiding the major drawbacks of these processes. The details of his presentation can be found in Paper ISC-14, "Enhanced Oil Recovery Using Hydrogen Peroxide Injection."

PANEL DISCUSSION

Following the panel presentation, the session was opened for discussion. Selected questions from the symposium participants and the panel members responses are summarized in this section.

Question by David Olsen, BDM-Oklahoma, Bartlesville, Oklahoma

Could the panel members comment on the feasibility of recovering oil from dolomite formations by thermal methods?

Response by Tom Buxton, Consultant, Tulsa, Oklahoma

Koch's combustion projects are in carbonates. The success of these projects is a testimony to the feasibility of combustion projects in carbonates. However, it is not clear what mechanisms are responsible for the success of these projects. I think, in general, the low-permeability and low-porosity characteristics of carbonate will have a negative impact, and the generation of CO_2 due to the decomposition of the carbonate will have a positive impact on the project performance. I have not come across any combustion tube runs done on carbonates. Perhaps Gordon Moore can clarify this aspect.

Response by Gordon Moore, University of Calgary, Canada

We do not have much experience with the carbonates. The one thing we do know for sure is carbonate tends to promote low temperature oxidation. However, from listening to Kumar's talk on the Koch project, I would guess that though the oil is being displaced, combustion is occurring in the low temperature region. The key to the oil production is the generation of CO_2 and not the temperature. If this is the case, you would have to use high gas flux to maintain production. Low flux will doom the project in carbonate reservoirs. Also, some knowledge about the energy generation due to the carbonate breakdown and its effect on the combustion reaction will be helpful.

Response by Jon Moss, Tejas Petroleum, Dallas, Texas

We did make some combustion runs using crushed dolomite. Although we could not match the porosity and permeability, we did notice extremely high CO_2 production. We felt it was due to the disintegration of the dolomitic material.

Response by Gordon Moore, University of Calgary, Canada

If you really want to make CO_2 from carbonate, go for a low temperature, wet combustion process. At low temperature, more acidic products are formed per unit of oxygen consumed, and the produced acidic water will react with the carbonate and enhance the carbon dioxide production.

The amount of CO_2 production by the acid reaction, however, will depend upon the equilibrium acid-carbonate reaction.

Question by Hal Gunardson, Air Products, Allentown, Pennsylvania

Gordon, I have a question for you. In your appraisal of the enriched air combustion technology, you commented that unless process variables are closely monitored, enriched air is likely to increase the low temperature oxidation reactions. My question is, Why this is so and how do you minimize LTO?

Response by Gordon Moore, University of Calgary, Canada

Low-temperature oxidation (LTO) reactions are promoted by low air fluxes in the oxidation zone. Although, operation at too low an air rate will guarantee it, there is no assurance that high air injection rate will not lead to LTO. This is because of the inherent maldistribution of air flux in any field project. The enriched air due to its higher oxygen content only aggravates the problem. Low-temperature oxidation reactions will also increase as you increase the oxygen partial pressure of the feed gas. LTO reactions are complex and very sensitive to operating conditions. LTO seems to promote formation of a coke film on the oil much like the way ice would form on a lake. The formation of a coke film at the gas-oil interface affects the rate of diffusion of oxygen into the bulk oil and has a significant effect on the combustion performance. By modifying air injection strategies, the role of LTO reactions can be minimized. By adopting a cyclic process involving high rate injection followed by periods of low rate injection, the LTO reactions can be minimized. This is because during the low rate, stored oxygen is released by starving the reactions of external oxygen.

Question by G. W. Russell, Consultant, Tulsa, Oklahoma

I have a question concerning emission in a combustion project. In some of the projects in Texas with which I am familiar, the produced gas had a terrible odor and smelled like hydrogen sulfide. Can one of the panelists comment on it and suggest ways to eliminate the odor?

Response by John Kirkpatrick, Consultant, Afton, Oklahoma

From your question, I surmise the projects that you referred to are associated with sulfur-bearing crudes. The sulfur compounds (such as the mercaptan) in such crudes may decompose upon heating to form H_2S. One way to eliminate the odor is to scrub them in a scrubber. Alternative to this is to flare them. Of course, you may have to mix natural gas with the combustion gas (which is mostly N_2 and CO_2) to burn them.

Comment by Gordon Moore, University of Calgary, Canada

We did a number of combustion tube runs with sour crudes. If you get a nice, clean high-temperature combustion, very little, if any, SO_2 or H_2S is found in the product gas. What you see are COS and CS_2. On the other hand, if the burn is not clean and low-temperature oxidation reaction is significant, then you are likely to see some H_2S in the product gas.

Question by Bill Brigham, Stanford University, Stanford, California

Does Koch experience any H_2S problem in their operation?

Response by Ron Miller, Koch Exploration, Wichita, Kansas

No, we did not. Our produced gas comprised principally of nitrogen and CO_2, with little bit of light hydrocarbons. We separated the hydrocarbon from the produced gas prior to venting it to atmosphere.

Question by Unknown Person

What is the sulfur content of your oil?

Response by Ron Miller, Koch Exploration, Wichita, Kansas

A weight percent of 0.43.

Comment by Bill Brigham, Stanford University, Stanford, California

That is a high enough sulfur content to cause problems. For some reason, you are not having problems with sulfur. Do you care to speculate?

Response by Ron Miller, Koch Exploration,Wichita, Kansas

In our Buffalo field combustion project, even though the produced is gas-odor free, the emulsion that plugged up the tube had an H_2S odor to it. In our Capa Madison Unit combustion project, even though the H_2S content of the produced gas was high (12%–15%), we did not have any smell. However, we could not vent it because of H_2S and had to burn it, after adding natural gas to it.

Question by Unknown Person

Have you considered injecting oxygen (enriched air) to burn up sulfur during combustion?

Response by Ron Miller, Koch Exploration, Wichtia, Kansas

Yes, we thought about it, but did not implement it due to economics. We felt we were benefiting from nitrogen because of its partial miscibility with oil at our reservoir condition and its effectiveness in displacing the oil. Further, enriching air with oxygen increases the operation cost while losing the benefits of nitrogen.

Comment by Gordon Moore, University of Calgary, Canada

If you generate those same gases using enriched air and do not have the dilution effect of nitrogen, you will get much more apparent generation and this will compound the disposal problem. I do not think oxygen is a savior to sulfur problem.

Comment by Carey Hardy, Consultant, Richardson, Texas

Allow me to make one last comment on the sulfur problem in combustion projects. I have been associated with projects where H_2S in solution in the oil came out of solution along with lighter hydrocarbon. In yet another project, the sulfur compound in the asphaltene upon combustion became the source of H_2S. Another common source of sulfur in the combustion project was the pyrite (iron sulfide) in the formation, which generally wound up as hydrogen sulfide in the produced gas.

Question for Jon Moss by Demetrios Yannimaras, Amoco Production Research, Tulsa, Oklahoma

Could you comment on the quality of hydrogen peroxide you used in your experiments? How stable is it? What is its half life?

Response by Jon Moss, Tejas Petroleum, Dallas, Texas

I do not now recall the quality of H_2O_2 we used in our combustion tube runs, but I think it was 50% quality. It is reasonably stable, but tend to decompose partially with time.

Question for Jon Moss by Demetrios Yannimaras, Amoco Production Research, Tulsa, Oklahoma

Could you describe your H_2O_2 combustion tube experiment? What is the content of the sandpack? How did you initiate the reaction between H_2O_2 and the crude and how much heat did you generate?

Response by Jon Moss, Tejas Petroleum, Dallas, Texas

We conducted two sets of runs to investigate the hydrogen peroxide process. For the first set, we packed the tube with clean sand and pumped water through it until the water saturation reached 21% PV. We then injected hydrogen peroxide through the pack. The rise in sandpack temperature provided indication, the liberation of heat due to decomposition of H_2O_2 into oxygen and water. In the second set, we packed the tube with sand containing 21% oil and 21% water and flowed H_2O_2 through it. The pack temperature reached 820° F. In both cases, the reaction was self-induced and appeared to be spontaneous. However, we do not have a good estimate of the heat generation, but the amount of heat generation was considerable. The sand contained some ferrous sulfate and this may have initiated the hydrogen peroxide decomposition. However, we are not sure of this. Our studies, though very preliminary, are encouraging and worth further investigation for field application. We described the process more fully in a paper submitted to DOE.

Comment by Dave Olsen, BDM-Oklahoma, Bartlesville, Oklahoma

The paper referred to by Mr. Moss will be included in the final symposium proceedings.

Question for Gordon Moore by Demetrios Yannimaras, Amoco Production Research, Tulsa, Oklahoma

Have you conducted any combustion tube runs on light oil with pure oxygen? If so, what is your conclusion?

Response by Gordon Moore, University of Calgary, Canada

No, we have not conducted any combustion experiments on light oil using pure oxygen. However, we conducted a number of runs on medium gravity oil (24° API) using enriched air (95% oxygen and 5% nitrogen). These experiments have shown that the oxygen and fuel requirements are functions of the total operating pressure and significant oxygen is reacted at the downstream of the combustion front. We have described these and other enriched air combustion tube run results in a number of SPE papers and other publications. If interested contact Matt [Matt Ursenbach] for the list.

Question for Carey Hardy, Consultant, Richardson, Texas, by Demetrios Yannimaras, Amoco Production Research, Tulsa, Oklahoma

From your presentation, it appears that you have associated with a number of in situ combustion field projects; which one do you consider the most successful and why?

Response by Carey Hardy, Consultant, Richardson, Texas

I was personally involved with 12 in situ combustion projects while I was with Sun and briefly reviewed five of them (May-Libby Project, LA; Trix-Liz Field, TX; Glen Hummell Field, TX; Gloriana Field, TX; and Iola Field, KS). In my presentation, I viewed the May-Libby combustion project as the most successful. This project, described in detail in a JPT article, encountered no major technical problem and the recovery was very high. From the economic point of view, May-Libby was Sun's most successful combustion project.

Question for Carey Hardy by Demetrios Yannimaras, Amoco Production Research, Tulsa, Oklahoma

What led to the technical and economic success of the project?

Response by Carey Hardy, Consultant, Richardson, Texas

May-Libby, which contains high gravity (40° API), low viscosity (3.0 cP at reservoir temperature of 135° F) was readily combustible and easy to flow. This led to high recovery. The air requirement was 240 Scf/ft^3, and oxygen utilization was 92%. The hot emulsion bank in the condensation zone of the combustion process was found to be very efficient in displacing the high gravity, low viscosity crude in this reservoir. Because of the high displacing efficiency of this emulsion zone, most of the oil was banked ahead of and within the condensation zone and produced. Further, the produced emulsion broke readily and minimized the operational problem. I attribute the technical and economic success of May-Libby project to good reservoir and crude characters that led to high recovery of a high priced crude and a relatively trouble-free operation resulting from good engineering.

Question for Representatives of Koch Exploration, Wichita, KS, by Alex Turta, Petroleum Recovery Institute, Calgary, Canada

Dolomite reservoirs are usually fractured, and in my opinion, it is difficult to evaluate the performance of in situ combustion in a fractured dolomite. Koch has demonstrated that combustion in dolomite reservoirs are both technically and economically feasible. So my question to Koch is, to what extent are the Buffalo and Medicine Pole Hills (Koch's dolomite reservoirs) fractured and what is its effect on combustion performance?

Response by Vinodh Kumar, Koch Exploration, Wichita, Kansas

We have very limited core data on these reservoirs, and they do not indicate any fractures.

Question from Alex Turta, Petroleum Recovery Insitute, Calgary, Canada

How about well logs and/or pressure analysis data?

Response by Vinodh Kumar, Koch Exploration, Wichita, Kansas

As far as I know, well logs and pressure data also do not indicate the existence of fractures in these dolomite reservoirs.

Response by Ron Miller, Koch Exploration, Wichita, Kansas

Although Buffalo and Medicine Pole Hills cores do not indicate any fractures, we did another combustion project in the Capa Madison unit field in northwestern Montana. This particular field was waterflooded prior to initiation of the combustion project. The premature breakthrough of water in certain producers indicated the existence of fractures and their direction. We designed the combustion project by staying away from the known fracture pattern and by not injecting air into those fractures. The core, pressure and production data from the other two projects (Medicine Pole Hills and Buffalo) definitely did not indicate the existence of fractures.

Question for Carey Hardy, Richardson, Texas, by Alex Turta, Petroleum Recovery Institute, Calgary, Canada

In the combustion projects you discussed, were the wells configured as line drive or as contiguous patterns?

Response by Carey Hardy, Consultant, Richardson, Texas

All of the projects that I have discussed were implemented as line drive. Glen Hummell was implemented as a line drive and the combustion was initiated at the structurally high portion of the reservoir and the combustion front moved down dip until it reached the last row of producers near the oil-water contact at which time, a new combustion zone was created. The Gloriana project was implemented as a double line drive. The May-Libby project was implemented as a top down line drive, i.e., starting from the upper part of the reservoir.

Question for Carey Hardy by Alex Turta, Petroleum Recovery Institute, Calgary, Canada

I presume the net pay thickness of the projects you described are all small; am I correct?

Response by Carey Hardy, Consultant, Richardson, Texas

Only the Gloriana had a net pay of 4 ft. The Glen Hummell, Trix-Liz, and May-Libby had a net pay of about 9 ft, and the net pay of Iola field was 20 ft. Even though average net pay thickness was thin for all projects except Iola, the net pay thickness was much higher in the structurally high part of the reservoir. The ignition was initiated in the thicker portion of the reservoir and spread out from there into thinner parts of the reservoir. This resulted in favorable oil recovery. For all the projects I described, the ultimate recovery was greater than 50% OIP.

Question for Carey Hardy by Alex Turta, Petroleum Recovery Institute, Calgary, Canada

Since all of the projects you discussed have a small net pay, your vertical heat losses are likely to be higher. In order to minimize the heat losses and advance the burning front at a reasonable rate, your injection rates must be high. But the data you showed indicate that your oxygen utilization efficiency is very high (greater than 90%), which means your injection rate must be low. How did you resolve this apparent conflict, and what was your philosophy regarding air injection rate?

Response by Carey Hardy, Consultant, Richardson, Texas

Yes, our oxygen utilization was high, which is one reason why we were able to achieve a high oil recovery. It is also true that vertical heat losses are likely to be high in thin reservoirs, and a minimum air injection rate is needed to overcome this loss and sustain combustion. However, air injection rate is limited by formation injectivity, the air compressor capacity and maximum safe gas producing rate. In our projects, the pay zone was overlain by shale zone which acted as a heat shield and minimized the vertical heat losses. Due to the combination of thin pay, high permeability and the presence of shale barrier above and below the pay, we were able to minimize low temperature oxidation and improve oxygen utilization at reasonable injection rate. We selected our air injection rate based on desired project life, compressor capacity, and formation injectivity.

Comment by Alex Turta, Petroleum Recovery Institute, Calgary, Canada

Although our distinguished panelist discussed at length the various aspects of successful combustion projects, no one addressed the issue of project failure. For every successful project reported in the literature, I am sure there may be several failed projects that go unreported. No one wants to talk about failed projects, and as such, one is forced to guess the causes for a failure. Too often we attribute failures to low oil saturation (lack of fuel to sustain combustion), low injectivity, reservoir heterogeneity, or lack of oil reactivity. No doubt one or more of these factors may have contributed to the failure of a project, but may not be the prime factor. One of the combustion projects I was associated with in Romania had a very low initial oil saturation, yet the project was an economic success. This suggests that performance of a combustion project is reservoir specific, and one should not rule out a candidate reservoir solely on the basis of a single parameter, such as low oil saturation or poor burning characteristic of the crude in the combustion tube. There are lessons to learn from failed projects, and good case histories of the failed projects will enhance our understanding of the process. This is my opinion, and I would like to hear the panelists' view.

Comment by Gordon Moore, University of Calgary, Canada

I agree with Alex. Failure often occurs because many operators view combustion as a last resort process and relegate it to fields where no other method had a chance of success. Failures were seldom attributed to the reservoir selection, but to the operational problems such as gas locking and emulsion formation.

From my experience, proper reservoir selection is the key to the success of a project. Combustion process is reservoir specific, and the reservoir whose rock and oil properties promote efficient oxygen utilization are more likely to succeed than those that promote low temperature oxidation. Low temperature oxidation alters the oil composition and promotes the formation of oxidized products. The oxidized oil is much more difficult to ignite than the original oil.

Many Canadian combustion projects failed due to lack of oil mobility. Oil mobility strongly influences the performance of an in situ combustion project conducted in a very viscous or bitumen containing reservoir or those containing high initial oil saturation. In such projects, adequate oil mobility is required in the cold portion of the reservoir, or air injectivity will be lost due to the formation of immobile oil bank downstream from the main high temperature region. This is the reason why combustion in reservoirs with high initial oil saturation often fail. Well spacing must be such that oils can be transferred from the region of mobilization to the production well. Relative permeability characteristics of the reservoir can also affect the project success. If the combustion product cannot be transported down stream due to poor relative permeability characteristics, stalling of combustion front will occur, and this will result in low temperature oxidation and poor combustion performance.

Comment by Jon Moss, Tejas Petroleum, Dallas, Texas

I have worked as a thermal oil recovery consultant for over 35 years and have associated with a number of combustion field tests. Based on my experience, I attribute many project failures to human factors and poor management decisions. By human factor, I mean poor engineering judgment or lack of understanding of the fundamentals of the process or operation. More often than not, lack of commitment on the part of the management is also to be blamed for many failures.

Comment by Tom Buxton, Consultant, Tulsa, Oklahoma

In my 40 years or so association with the oil industry, I came across both successes and failures. In my opinion, neglect of details can doom a project. Only those companies that man the project with experienced people and pay attention to day-to-day operation and problems can count on success.

Question by Unidentified Person

I was associated with a combustion project that failed due to backburning. What causes it? How do you prevent it?

Response by John Kirkpatrick, Consultant, Afton, Oklahoma

Backburning was a problem in some of the earlier combustion projects, where the operator relied on autoignition to initiate combustion. Autoignition is feasible in reservoirs whose temperatures are sufficiently high (greater than 120° F) and contain a reactive oil. When air is injected into a well, the temperature around the wellbore falls due to absorption of heat by the air. However, as the warm air moves further into the reservoir, slow oxidation takes place and heat is given off. If the amount of heat released is greater than the loss to the overburden, reservoir temperature will rise, and this in turn will increase the oxidation rate. If this condition continues, reservoir temperature continues to rise until there is spontaneous combustion at some distance from the well. After spontaneous ignition, the combustion front moves backwards towards the injection well before taking off in the direction of air flow. This backward movement or backburning occurs because the reservoir is warmer behind the front than ahead and rich in oxygen due to air flow.

The distance between the injection well and the point where ignition is provoked depends upon the air flow rate; the higher the flow rate, the greater will be the distance. Use of enriched air will aggravate the backburning problem, because it promotes a much higher oxidation rate and hence a much higher temperature. You can avoid backburning altogether by starting the ignition around the injection well with the help of a downhole igniter and allow the combustion front to move forward. Failure of the compressor soon after the initiation of autoignition will also result in backburning.

Question by Unidentified Person

I have a question for John Kirkpatrick. Your presentation covered only the compressor problems; what about production problems? Do you have any recommendation or advice?

Response by John Kirkpatrick, Consultant, Afton, Oklahoma

The operating problems associated with a combustion project are many and the extent of the problems vary between wells and projects. The major problems include reduction in well productivity due to combustion gas production, emulsion, corrosion of pumps and surface facilities, and sand production problems. Venting at the wellhead is the usual method of handling produced gases. Due to increasingly stringent environmental regulations, it may be necessary to scrub the gas before venting. Corrosion due to acid gas production and high temperature is a common problem for in situ combustion projects. Implementation of a corrosion monitoring, and inhibition program is one partial solution to corrosion problems. Use of hardened and honed pump barrels with stellite seats and a lubricated plunger may help reduce pump corrosion. Sand problems can be reduced by matching pump withdrawal to wellbore inflow, thereby ensuring that the fluid is in motion and the sand is kept in suspension.

Comment by Doug Cathro, Canadian Liquid Air, Calgary, Alberta, Canada

Jon Moss talked about the advantages of the hydrogen peroxide oil recovery processes, but made no reference to the cost, and I would like to comment on it. Jon's data are based on 100% H_2O_2, and to illustrate his point, he mentioned that the amount of oxygen liberated from the decomposition of 75 bbl of 100% H_2O_2 is roughly equivalent to the oxygen content of 1,000 Mcf air. Seventy-five barrels of pure H_2O_2 weigh approximately 13.2 tons, and in Canada H_2O_2 sell for about $1,000/T. So the process is not cheap, and moreover, H_2O_2 is generally produced at

70% concentration to avoid decomposition and diluted to 30% before shipping. At 30% H_2O_2 is very stable. For the process to be economic, H_2O_2 must be produced on-site in large quantities.

Question by Jeff Weissman, Texaco, Glenham, New York

It is generally an accepted practice in the industry to perform combustion tube runs prior to undertaking a field project. My question to the panel is, how well do the combustion tube results, such as the air requirement and fuel consumption values, agree with field values?

Response by Carey Hardy, Consultant, Richardson, Texas

In most of the projects I was associated with, the two results agree reasonably well. However, first a word of caution. If the lab tests were performed using synthetic cores, such as quartz, expect considerable scattering and poor agreement.

Comments from Gordon Moore, University of Calgary, Canada

You may be able to predict field results from combustion tube runs, provided both are performed in high temperature mode. The main reason that field projects deviate from the combustion tube prediction is the existence of low temperature oxidation reaction in the field. Low temperature oxidation (LTO) leads to low oil displacement efficiency. The role of LTO reactions can be minimized by appropriate air injection strategies. High air fluxes usually favor high temperature combustion.

Question by Tim Ellison, Mobil Oil, Dallas, Texas

We heard this morning that the Bureau of Mines was unsuccessful in sustaining combustion in low-permeability reservoirs. Another author espoused the virtue of doing a line drive combustion project. I would like to hear the panel's view on the desirability of doing a line drive type combustion project in low-permeability reservoirs, where both the injection and producer are hydraulically fractured and linked.

Response by John Kirkpatrick, Consultant, Afton, Oklahoma

Sustaining a combustion front in a fractured reservoir is a difficult thing to do because of the bypassing of the air through the fractures. We were not able to sustain combustion in the laboratory fractured cores. If you can control the air from channeling through fractures, you may be able to propagate the front.

Comment by Gordon Moore, University of Calgary, Canada

You may want to talk to BP. Their pressure-up blowdown combustion process may be applicable to fractured low-permeability reservoirs.

KOCH'S EXPERIENCE WITH DEEP IN SITU COMBUSTION IN WILLISTON BASIN

Key Note Address by R. J. Miller, Koch Exploration Company, Wichita, Kansas

INTRODUCTION

Koch Exploration Company has been active with the combustion process in the Williston basin of North and South Dakota since 1979. Koch has three ongoing combustion projects in the basin, as indicated in Figure 1. The Medicine Pole Hills Unit (MPHU) and the Capa Madison Unit (CMU) are located in the North Dakota, while the Buffalo Unit is situated in South Dakota. Because of low primary recovery from these deep carbonate reservoirs, studies were conducted to determine how the large volume of remaining oil could be recovered, and decisions were made to initiate an in situ combustion by air injection, pressure maintenance project in these reservoirs.

The principal objective of my talk is to review the past performance of these combustion projects and discuss some of the operating problems we encountered. The other objectives are to outline the economics of the projects and to speculate on the future of in situ combustion technology as Koch sees it.

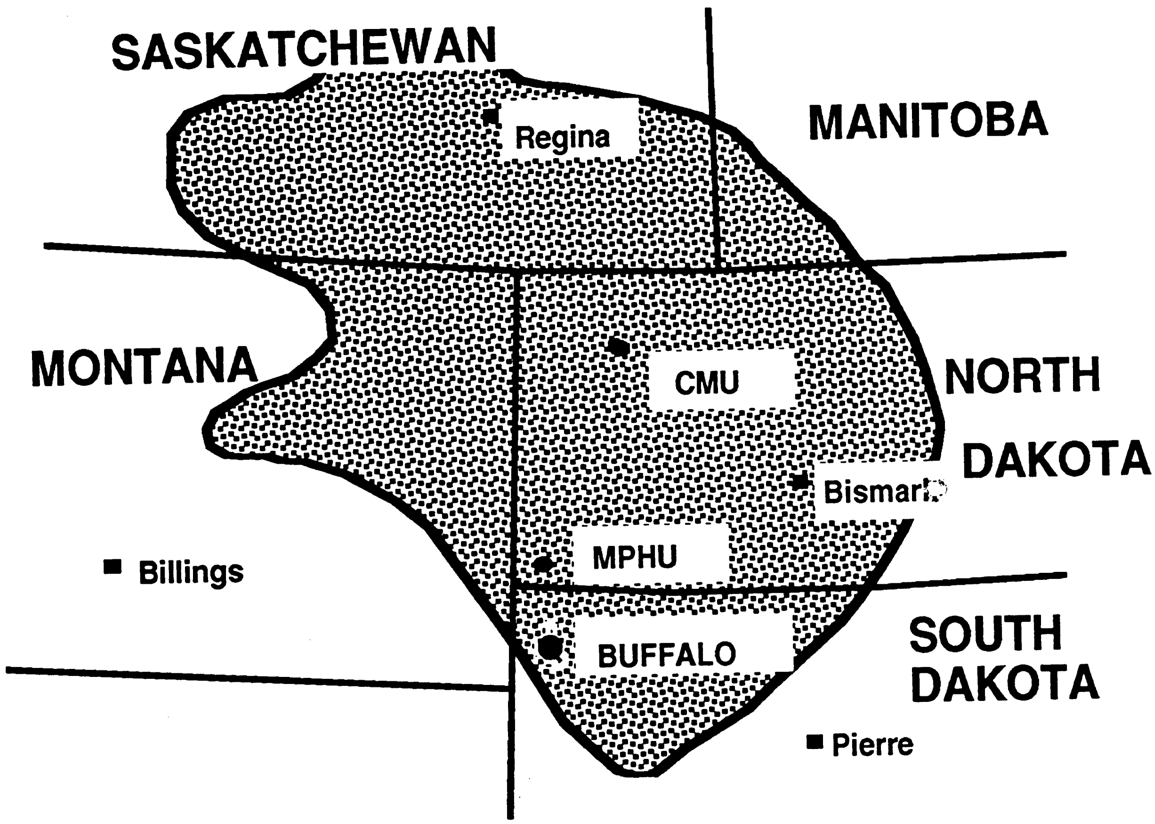


FIGURE 1 Location of Koch's in situ combustion project sites.

PROJECT DESCRIPTION

Medicine Pole Hills Unit (MPHU)

The Medicine Pole Hills field, Bowman County, is located in the southwest corner of North Dakota (Fig. 2). The field produces from the Red River carbonate formation, that occur at an average depth of 9,500 ft. The field was discovered and developed in 1978. It produced approximately 15% of the oil in place by primary means, which was primarily liquid and rock expansion with a partial waterdrive. The reservoir and fluid properties are shown in Table 1.

Due to low primary recovery, several alternatives were considered for improving the recovery and the air injection in situ combustion process was selected. Air injection was selected in preference to other methods, such as waterflooding, primarily because of the success of the air injection combustion project in the Buffalo field, located 20 miles south of Medicine Pole Hills field. Both these fields have similar reservoir properties and produce from the Red River formation.

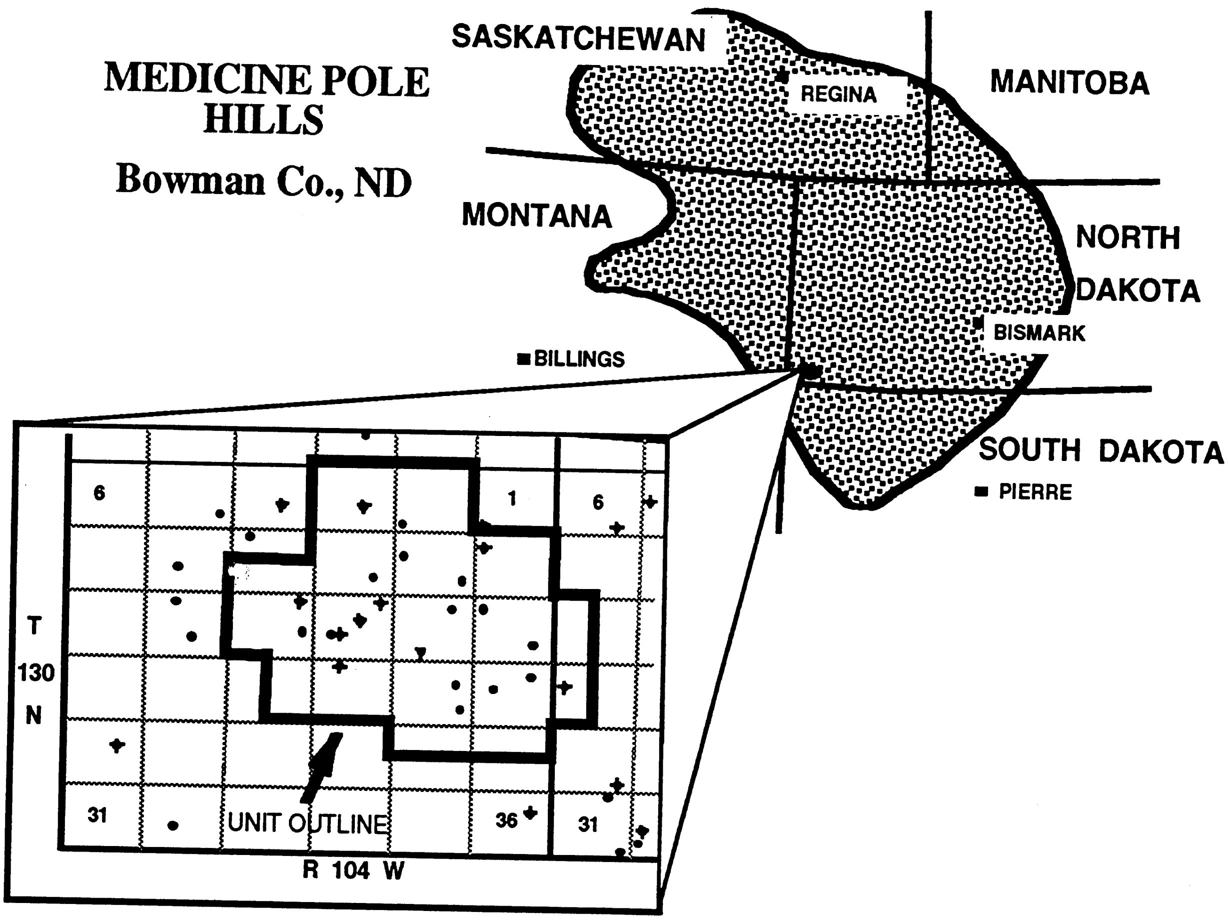


FIGURE 2 Medicine Pole Hills Unit outline and well status.

TABLE 1
Koch Combustion Project—Reservoir and Fluid Properties

Properties	MPHU	Buffalo	Capa Madison
Formation	Red River	Red River	Madison
Total depth, ft	9,500	8,450	8,400
Net pay, ft	18	10	20
Permeability, mD	5	10	1
Porosity, %	17	20	10
Water Saturation, %	43	45	42
Temperature, °F	230	215	226
Original OIP, bbl/ac-ft	530	735	250
Gravity, °API	39	31	43
FVF, Rb/STB	1.4	1.16	1.62
Oil Viscosity, cP	0.48	2.1	0.28
Bubblepoint, psi	2,246	3,000	3,317

The MPHU covers 9,600 acres. Figure 2 shows the unit outline and current well status. The unit, formed in 1985, contains 13 producers and seven injectors on 320-acre spacings. For more details on the geology and primary recovery history of the field, see SPE 27792 presented at the 1994 Tulsa EOR meeting.

The high pressure air injection began in October 1987 in the eastern lobe of the unit, and the cumulative air injection as of December 1993 is 12 Bscf. Currently, air is being injected at a rate of 9 MMscf/D at 4,400 psi into seven wells. The MPHU production performance is shown in Figure 3. The oil production has increased from about 400 bbl/D prior to initiation of the project to the current rate of 950 bbl/D, while the number of producing wells remained the same. The peak oil production was 1,200 bbl/D. The project produces natural gas liquids (NGL) along with the oil, which is recovered in the gas processing plant. Over the past two years, the NGL recovered from the gas processing plant has increased to about 200 bbl/D due to stripping of the light ends by the in situ generated flue gas. The incremental oil production to date from this project is about 1.1 million bbl, and the WOR has remained constant at about 1 bbl/STB since the air injection began. I will discuss the Buffalo field project next.

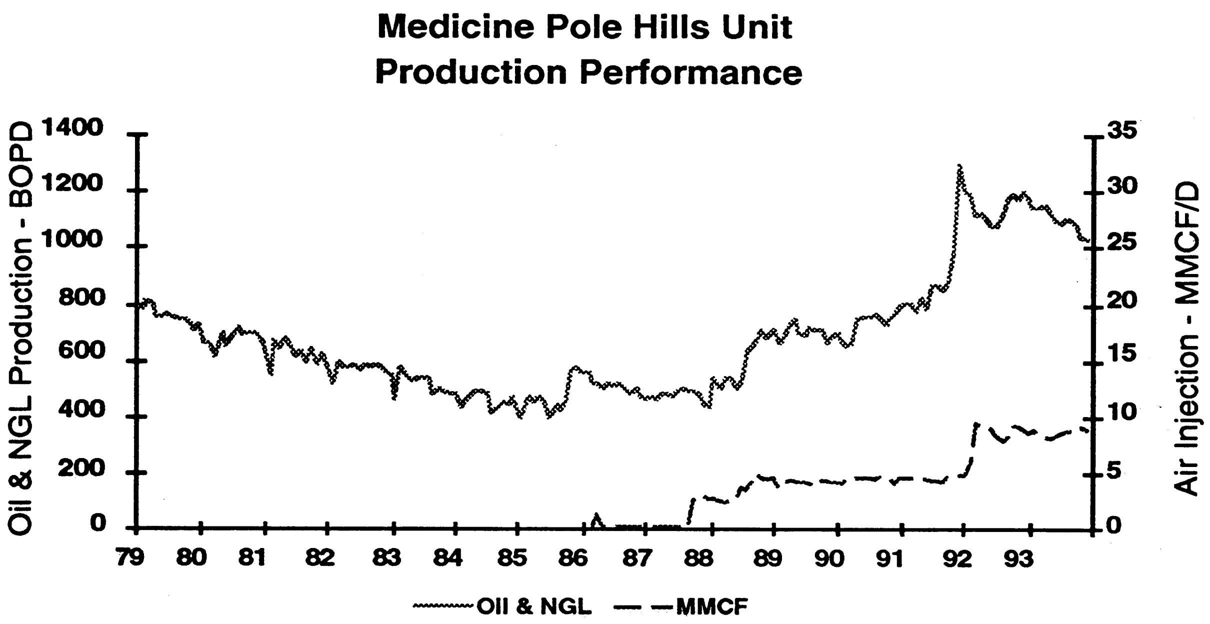


FIGURE 3 MPHU production performance (1979–1993).

Buffalo Red River Units

The Buffalo Red River field, Harding County, is located in the northwest corner of South Dakota (Fig. 4). The Koch Buffalo Red River project comprised three units, which we called the Buffalo Red River Unit, the South Unit, and the West Unit. Together they cover approximately 30,000 acres (Fig. 4). The combustion project was implemented as a pilot in the Red River Unit in 1979 and later was expanded to field wide. The South Unit combustion project was started in 1983, and the air injection in the West Unit was initiated in 1987. The three units together currently have 30 injectors and eight producers in an inverted 9-spot pattern on 160-acre spacings.

The reservoir and fluid properties are shown in Table 1. The reservoir rock is a dolomite found at an average depth of 8,400 ft. The gross pay is 19 ft, and net pay averages to about 10 ft. The OOIP is 735 bbl/ac-ft, and reservoir pressure is 4,500 psi. The oil gravity is 31° API, which is lower than the 39° API at MPHU. The reservoir is undersaturated with a bubblepoint pressure of 3,000 psi.

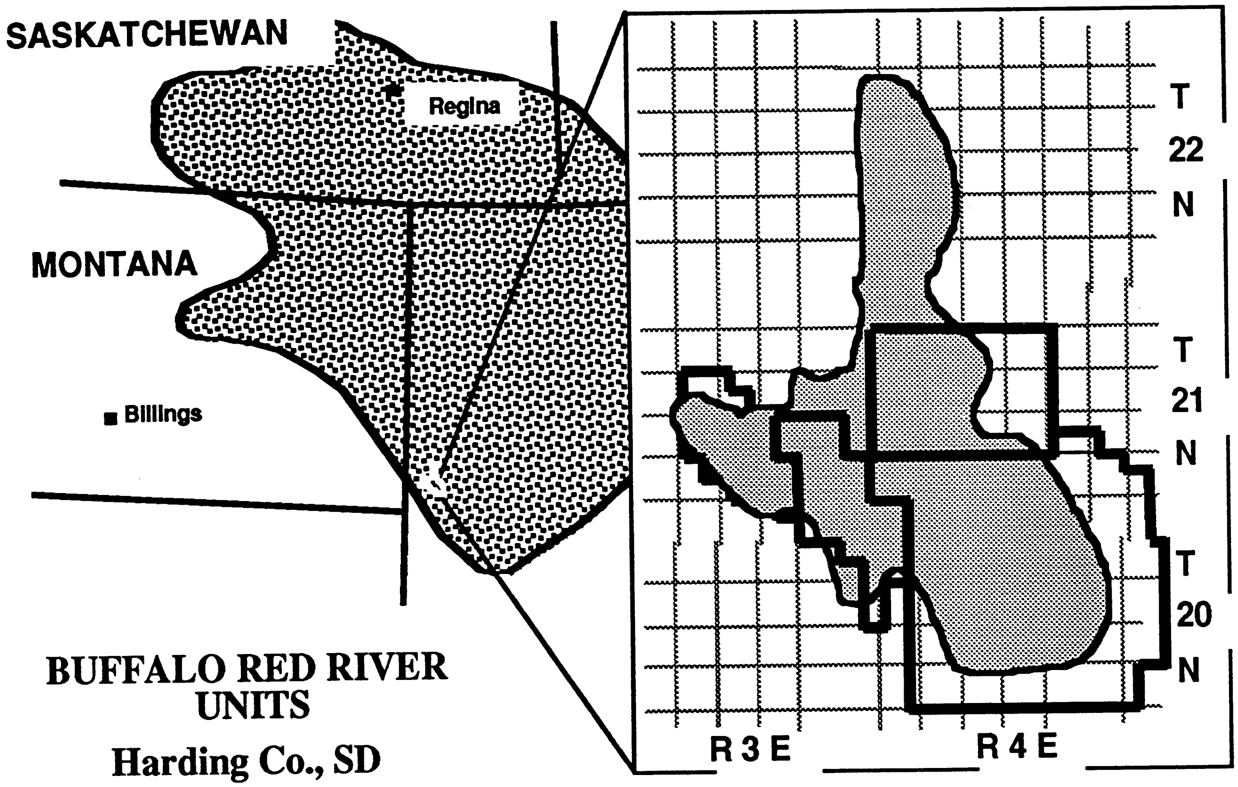


FIGURE 4 Buffalo Red River Units project site.

The high pressure air injection began in mid-1979 in the Buffalo Red River Unit. Air injection in the South Unit was commenced in early 1983 and in the West Unit in 1987. Currently, the air is being injected at the rate of 33 MMscf/D and pressure of 4,400 psi into 30 injectors. During the period of 1987 to 1993, while the project was being expanded by the addition of new injection wells, the compressor capacity did not keep pace with the expansion. As a result, during this period there was an underinjection of air. In early 1994, a compressor with a rated capacity of 13.3 MMscf/D was brought on stream and boosted the project injection capacity to 43 MMscf/D.

The combined Buffalo Red River Unit's production performance is shown in Figure 5. It is clear from this plot that even with underinjection, oil production increased from 1,000 bbl/D prior to the commencement of air injection in 1979 to a peak of 2,800 bbl/D in mid-1991. The cumulative air injection as of December 1993 was about 90 Bscf and the incremental oil production to date (December 1993) from this project was about 10 million barrels, giving an average air to oil ratio of about 9 Mscf/STB.

Capa Madison Unit (CMU)

The last project I am going to talk about is the Capa Madison Unit combustion project, implemented in the Capa Madison field in Williams County, North Dakota. The field is located in the north central part of North Dakota (see Fig. 6) and produces from two zones, the Mission Canyon zone and the Madison zone. The field has undergone both primary and waterflood. The combustion project was implemented in the Madison zone.

The reservoir and fluid properties are shown in Table 1. The Madison zone found at an average depth of 8,400 ft is a fractured carbonate with an average permeability of 1 mD and 10% porosity. Capa Madison is a poor quality reservoir in comparison to MPHU and the Buffalo Red River Unit with an OOIP of only 250 bbl/ac-ft.

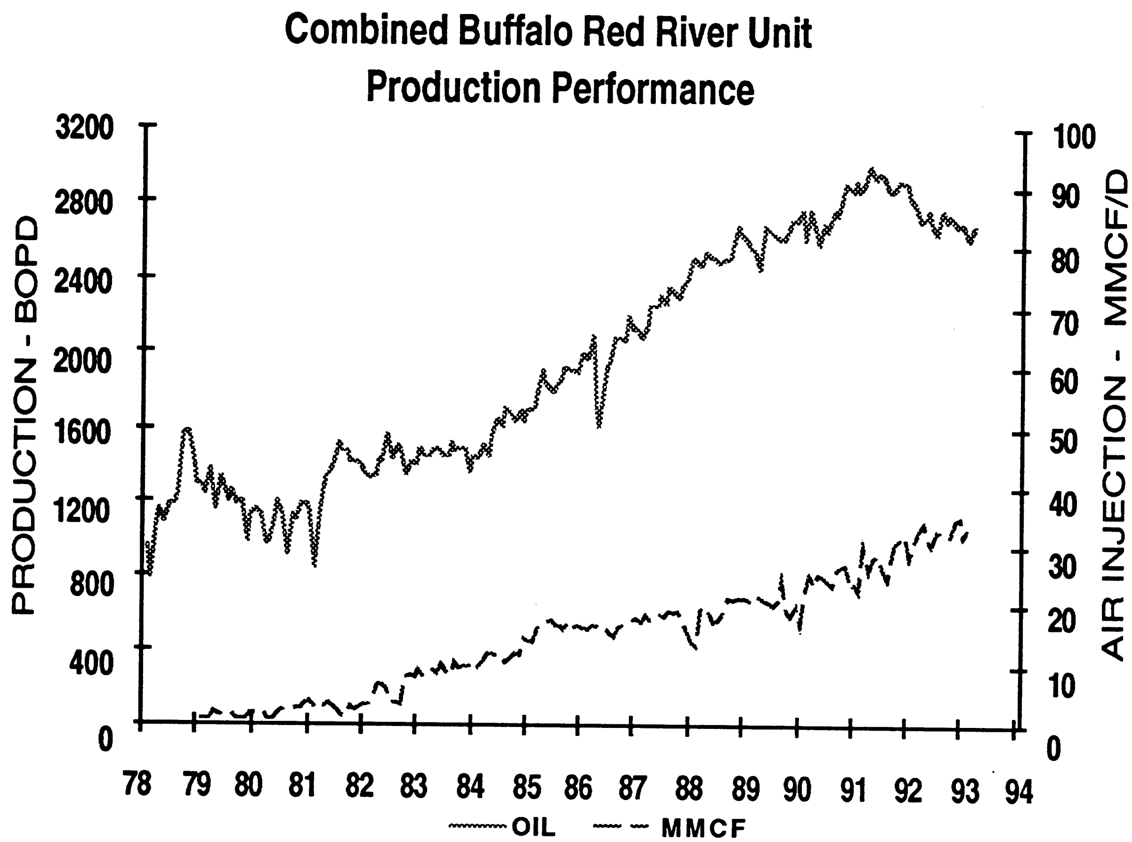


FIGURE 5 **Combined Buffalo Red River Unit production performance (1978–1993).**

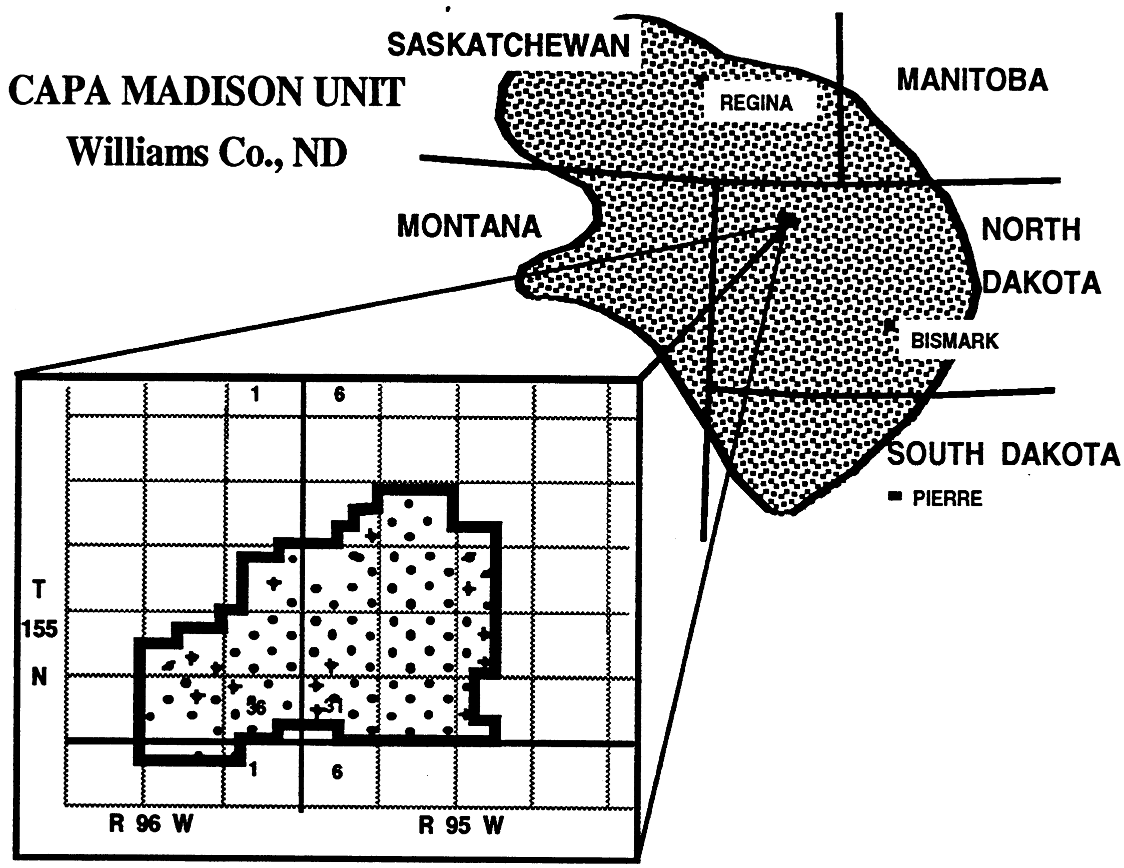


FIGURE 6 Capa Madison Unit project site.

The air injection project was initiated in mid-1984 in the eastern lobe of the field. The project contains four injectors and eight producers on 160-acre spacing. The air injection limited by the compressor capacity was restricted to 4 MMscf/D and a quick production response was noted. The production jumped from a preinjection rate of 125 bbl/D to 275 bbl/D. The air injection was terminated after two years of injection due to high operation costs and lack of processing facility to process the H_2S contaminated flue gas prior to venting. Though the air injection was discontinued in 1986, the field continued to produce to date at a rate well above the pre-air injection production rate. The production performance of Capa Madison Unit is shown in Figure 7. The cumulative air injection was about 2.4 Bscf and the incremental oil due to air injection was about 78,000 barrels giving an average air/oil ratio of about 30 Mscf/STB.

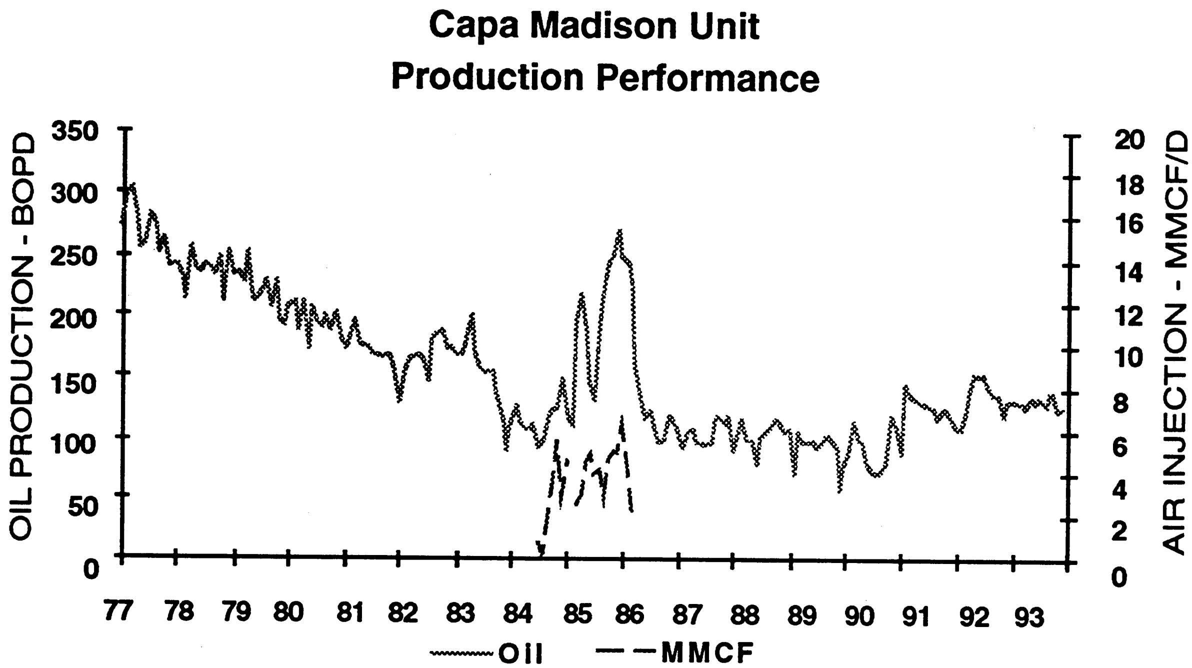


FIGURE 7 Capa Madison Unit production performance (1977–1993).

Let me digress briefly to comment on the screening parameters. In Table 2, the most often cited screening guides for in situ combustion processes are compared with the rock and fluid properties of Koch's projects. From this table it is clear that our projects violated almost all of the recommended screening guides, yet proved to be commercially successful. So do not rule out a process simply because your reservoir parameters lies outside the range of recommended values.

TABLE 2

Published Screening Guides vs. Koch's Combustion Project Parameters

Properties	Iyoho[1]	Chu[2]	MPHU	Buffalo	Capa Madison
Net pay, ft	5–50	-	18	10	20
Porosity, %	>20	>16	17	20	10
Permeability, mD	>300	>100	5	10	1
Oil Saturation, %	>50	>35	57	55	58
Gravity, °API	10–40	>40	39	31	43
Oil Viscosity, cP	>1,000	-	0.48	2.1	0.28
$\frac{Kh}{\mu}$, mD-ft/cP	>20	>10	187	48	71
$\emptyset S_o$	>0.077	>.10	0.10	0.11	0.06

[1] Iyoho, A. W. "Selecting EOR Processes," *World Oil* (November 1978)
[2] Chu, C. "State-of-the-Art Review of Fireflood Field Projects," SPE/DOE EOR Symposium, Tulsa (April 1981).

OPERATIONAL PROBLEMS AND THEIR REMEDIES

The operational problems that plagued the projects are no different from those experienced by other in situ combustion operators. The major problems we encountered included explosion hazards, injection well failures, inadequate compression volume, corrosion, poor sweep efficiency with high inert gas production, flue gas disposition due to high H_2S content, compressor design and efficiency, and unitization problems. Let me summarize these for you.

Explosion Hazards: Despite the use of synthetic lubricants, our compressor facilities encountered three explosions early in the life of the projects due to the presence of small amounts of rust in the interstage piping. We used two approaches to eliminate the problem. We cut the lube oil circulation rate below that recommended by the manufacturer, and secondly we periodically steam cleaned the interstage piping and flushed them with nitrox solution. Other actions taken to prevent potential explosion included periodic inspection of lubricant collection points and draining off any excess lubricants.

Injection Well Failures: Corrosion is the principal cause of injection well failure, especially when the bottomhole temperature is high. We had several injection well failures in our Buffalo Red River Units due to the extremely corrosive downhole environment. Any tubing leak will result in high pressure wet air that is conducive to corrosion. Even a small leak of 20 ft^3 per day will cause major corrosion problems in tubing and casing over a period of less than a year. Small leaks are very difficult to detect at the wellhead. Most of our injection wells have 5-1/2 in. K-55 and N-80 grade casing and 2-7/8 in. tubing. We isolated the annulus using a permanent type injection packer and filled with corrosion inhibitors to minimize corrosion. In some wells we used modified coupling for tubing with some success. Injectors drilled since 1992 have coiled tubing to eliminate potential tubing leak. We also used a strong oxidizer as the tubing-annulus packer fluid in some wells to retard corrosion.

Inadequate Compression Volume: Inadequate compressor capacity was a major problem in our Buffalo and Capa Madison projects. The Buffalo Red River Unit project was initiated as a pilot and expanded several times. The air requirements for pilot and large scale operations are different. The air requirements are small for a pilot and smaller capacity compressors are adequate. But as the project expands, the air requirements also increase and the available compressor capacity must be adequate to meet this demand. In the Buffalo project, the available compressor volume did not keep pace with the requirement, resulting in underinjection. One cannot increase the compressor capacity at will, and good planning is a key. We eventually brought the compressor capacity in line with our requirement, but at added cost.

Corrosion in High GOR Wells: Produced fluids and gases from fireflood projects are often severely corrosive. In our projects, corrosion was severe in high GOR wells due to production of acid combustion products such as carbon dioxide and hydrogen sulfide. Corrosion was minimized by circulating corrosion inhibitor chemicals below the packer and through the use of plastic-coated tubing. Another approach undertaken to minimize corrosion was through squeeze jobs; however, the major problem was the integrity of squeeze jobs.

Poor Sweep Efficiency with High Volume Inert Gas Production: This particular problem was encountered in our Buffalo Red River Unit where the ISC is being conducted using pattern configuration. In this project, we used a 160-ac well spacing to utilize existing wells. However, due to surface location, we drilled two off-pattern wells, one of which was converted into an injection well. This well was much closer to the producer than any other injectors in the project. Injection of air into this well resulted in oxygen breakthrough in the nearest producer; thus, low oil and high inert gas production. Attempts to stimulate the well with acid frac treatments have failed, and one decision was made to shut the well down. The well is currently being used as an observation well to monitor the reservoir pressure. Since it costs in excess of $800,000 to drill and equip a well in this area, we are currently considering converting this well into an injector.

Flue Gas Disposition with High Hydrogen Sulfide Content: This problem was encountered in our Capa Madison project. The H_2S content of the flue gas began to increase soon after the beginning of the air injection and the gas plant contracted to process the flue gas declined to process the gas. This created the problem of disposal of sour flue gas. We were given two choices: either install a gas processing plant at the site to process gas or stop injecting air. Since it costs in excess of $2 million to install a processing plant and the project was only marginally economical, we decided to terminate the air injection.

Compressor Design and Efficiency: This problem arose in the huge Buffalo field operation, where the project was initiated as a small pilot and expanded in phases. Since air requirements are smaller for a pilot operation, one normally opts for a small compressor, as we did. Smaller compressors are less efficient, more expensive to operate, and supply air at higher unit cost compared to a larger capacity compressor. Not knowing exactly what size compressor will meet the current and future project requirements, we purchased compressors that were oversized at the initial stages and soon became undersized with expansion. In the Buffalo project, for several years we ended up using an undersized compressor. Recently, we brought on-line a 5,000 psi, 13 MMscf/D compressor to meet our current project requirement.

Unitization Problems: This is a problem that I am sure every unit operator has to cope with, and particularly if you are in a new area. We were forced to go to the State Supreme Court over the unitization of our South Buffalo Red River Unit.

Economics: Let me briefly address the economics of our combustion projects. Both MPHU and Buffalo Red River Units were economically successful. Since these fields were not fully developed, we expended a considerable sum in doing developmental drilling in addition to combustion project costs.

Experience played a major role in the economics of these projects. The projects were conducted in a frontier area, and at the early stages of the projects, we encountered all sorts of injection facilities problems and our operating costs exceeded $28/bbl. That was the price we paid for learning. The capital investments for the MPHU air injection project are given in SPE 27792. Based on incremental EOR oil production of 3.6 million bbl, the MPHU reserves have been developed for a capital expenditure of $3.90/bbl. Air injection projects are energy intensive and the availability of low-cost electricity at the site will greatly enhance the economics of the project. At present in our Buffalo Red River Unit project, energy costs account for 40% of the total operating cost.

FUTURE OF IN SITU COMBUSTION

In my opinion, high pressure air injection/in situ combustion process has great potential in recovering oil economically from deep reservoirs, provided the wellhead price stays above $18/bbl. There are many fields in the U.S. similar to ours, and they contain in excess of 60 billion bbl of oil. Projects like ours is one economical way to produce oil. I, however, also recognize significant reservoir and production related problems remaining to be solved and am also confident in our ability to overcome these problems and produce oil economically.

DISCUSSION

Question from an Unidentified Person

Given Koch's long history and experience in conducting in situ combustion projects, what would your capital and operating costs be if the project is to produce 10,000 bbl/D instead of 2,000 bbl/D?

Response by Ron Miller

No, I cannot give you a definite cost figure, because every project is unique. As I mentioned earlier, the energy costs play a major role on the economics of projects such as these. It is relatively easy to compute the compressor size and pertinent upfront costs, but operating costs are difficult to predict and defy scaling.

Question from an Unidentified Person

Is it feasible to produce oil from these deep tight reservoirs by injecting water?

Response by Ron Miller

Yes, it is possible, but requires an awfully long time to drain the reservoir. The water intake of the Buffalo Red River Unit is about 70 bbl/D per well. At this rate, it would take in excess of 20 years just to fill up the reservoir. An operator who discovered a field next to ours in the same formation started injecting water right away to maintain the virgin pressure. He is injecting about 80 bbl of water per day per well and producing 60 bbl of oil per day per well. In our case, the reservoir pressure is 800 psi, which is well below initial reservoir pressure of 4,000 psi, so it would take a lot of time to pressure up the reservoir with water.

Question from Bill Brigham, Stanford University, Stanford, California

Did you consider using oxygen or enrich air in your projects?

Response by Ron Miller

Yes, we seriously considered injecting oxygen to minimize the inert gas production and disposal problems, but did not implement it due to the excellent response from air injection. At our reservoir condition, nitrogen is partially miscible with the crude and this enhanced the recovery. Moreover, in our opinion, the oxygen process presents more operational problems and may not be cost-effective compared to the normal air injection process.

Question from Dave Olsen, BDM-Oklahoma, Bartlesville, Oklahoma

All of your facilities appeared to be housed inside. Is there any particular reason for that?

Response by Ron Miller

We housed all of our facilities inside to protect our equipment from the harsh Dakota winters. This is necessary because the air temperature in winter is well below the pour point of the cylinder lubricants and a frozen lubricant can damage the compressor cylinder. We also bury all of our air lines 8 ft below the ground to prevent the condensation and freeze up of the moisture.

Question from Dave Olsen, BDM-Oklahoma, Bartlesville, Oklahoma

If you had to do these projects all over again, what would your well configuration be?

Response by Ron Miller

I think we would go for a line drive rather than a pattern drive configuration as is our present case, simply because of its inherent advantages over pattern drive, as pointed out in one of the presentations this morning [Paper ISC-3]. However, keep in mind that each project is unique and it will probably dictate the type of configuration it can accommodate. For example, in our MPHU project where we had to drill through salt section the drilling program had to be designed to prevent casing collapse problem. Since it is very expensive to drill through salt section, we drilled new wells around the existing wells in a configuration that gave best flow performance.

Question from Alex Turta, Petroleum Recovery Institute, Calgary, Canada

In the projects you just described, did you use an igniter to initiate combustion? If not, how did you ensure that it is indeed a combustion process? Did you measure bottomhole temperature?

Response by Ron Miller

No, we did not use any igniter to initiate combustion. The reservoir temperature is high enough to initiate autoignition, and the crude was reactive enough to sustain combustion front. Although we did not measure the bottomhole temperature, we surmised combustion from the produced gas analysis. The CO_2 content went up from 0% to 12%. The flue gas analysis also indicated the presence of smaller amounts of light hydrocarbons. The acrid smell of the flue gas was also an indication of burn.

Question from Bill Brigham, Stanford University, Stanford, California

What is the oxygen content of your flue gas?

Response by Ron Miller

Zero, except for one well in the Buffalo Red River Unit project, where we had an oxygen breakthrough.

Question from an Unidentified Person

Did you achieve any miscibility? If so, how much of the recovery is due to miscibility?

Response by Ron Miller

Our reservoir pressure is well above the CO_2 minimum miscible pressure for the crude. We confirmed that through lab tests. N_2 is also partially miscible with the crude at the existing reservoir conditions. I do not have any number as to what percentage of recovery is due to miscibility and how much is produced by frontal displacement.

Question from Bill Brigham, Stanford University, Stanford, California

Your presentation revealed the occurrence of a significant vaporization and stripping of lighter ends. How much NGL (natural gas liquid) did you recover from the produced gas?

Response by Ron Miller

In the Medicine Pole Hills project, we are recovering approximately 200 bbl/D of NGL in the refrigeration plant since May 1991. As of 1993, we have recovered more than 155,000 bbl NGL.

Question from an Unidentified Person

Have you thought about putting sensitive pressure transducers, instead of pressure gauges at the injection wellhead to detect minute casing leaks?

Response by Ron Miller

No, we did not. It is a good idea, and we may look into it.

Question from Tom Buxton, Consultant

What is the hydrocarbon content of your produced gas? Can you use this information to back calculate and estimate the volume of reservoir burned?

Response by Ron Miller

No, we do not have a complete analysis of our produced gas. Our field chromatographs can only separate five components. This is not sufficient to estimate burned volume.

Question from an Unidentified Person

You mentioned in the initial stages of the Buffalo project that you did an isolated pattern burn. Did you observe any response in the off-set wells? If so, what was the ratio of production between the pattern wells and off-set producers?

Response by Ron Miller

We started the Buffalo project with one injector and one producer. This producer showed immediate response, long before any other well in the area. To answer your question, yes, the off-set wells responded to air injection. However, I do not have any firm numbers on the off-set well production due to combustion.

Question from Gordon Moore, University of Calgary, Canada

From your injection and production well data, can you discern what the flow pattern is likely to be?

Response by Ron Miller

I am not sure that I can map the flow pattern because our well configuration is not clear cut. In some areas, we had two producers inside two injectors, and it is relatively simple to figure out the nitrogen flow direction. In other areas, the well arrangement was much skewed, and the flow pattern is not so obvious.

Question from D. Mamora, Texas A&M University, College Station, Texas

Did you make any combustion tube runs on your 43° API (Capa Madison) oil? If so, what was your fuel concentration?

Response by Ron Miller

Yes, Jon Moss did the combustion tube runs on this crude, and he may be able to answer your question.

Response by Jon Moss, Tejas Petroleum Engineers, Dallas, Texas

An oil that light does not burn smoothly in our tubes. It showed one quick temperature peak and as soon as the plateau built up, it quit burning. So I cannot say what the fuel lay down would be.

Comment by an Unknown Person

It simply vaporizes, and there is nothing left to burn.

Question from D. Mamora, Texas A&M, College Station, Texas

Did you see any difference in performance between the 30° API and 40° API crude run?

Response by Jon Moss, Tejas Petroleum Engineers, Dallas, Texas

The fuel lay down was higher with the 30° API oil.

Question from an Unknown Person

How did the two crudes respond in the field? Did one perform better than the other?

Response by Ron Miller

We use economic yardstick to measure the performance of a project. We judge a project by the amount of money it makes and not by the amount of oil it produces. Using this criteria, I would say the Medicine Pole Hills project (39° API) is a better performer than the Buffalo Red River Unit project (31° API). Although the daily production was higher in the Buffalo project, the MPHU wells performed better. The initial average daily per well production rate of MPHU wells is 300 bbl, while the best Buffalo well produces only 150 bbl/D. Further, we are stripping NGL from MPHU flue gases, whereas the Buffalo flue gases are lean. In the economic sense, MPHU is a better performer than Buffalo.

Comment by an Unknown Person

These two reservoirs differ in many ways. In one case, you are dealing with a fractured limestone with very little primary porosity, while the Buffalo is a dolomite containing low gravity oil.

Response by Ron Miller

The two fields are only 20 miles apart. Both fields produce from the Red River formation and have similar reservoir characters, except for the depth.

Question from Gordon Moore, University of Calgary, Canada

Please correct me if I am wrong. You are saying only the MPHU is producing NGL, while Buffalo does not. Why?

Response by Ron Miller

You are right. In the Buffalo unit we do not have any processing plant, and we simply direct the produced gas into a tank. Some of the light ends drop out, but not all. The amount of condensate in the vent gas is not sufficient to economically justify the installation of a processing plant.

Question from Gordon Moore, University of Calgary, Canada

How much condensate does the produced gas carry with it?

Response by Ron Miller

In the Buffalo field it is very small, about 1 gal/1,000 Mscf, and in the medicine Pole Hills project it is currently about 2.5 gal/1,000 Mscf, and at the start of the project it was about 6 gal/1,000 Mscf.

Question from D. Yannimaras, Amoco Production Research, Tulsa, Oklahoma

Your Capa Madison reservoir showed immediate production response to air injection, and if I remember correctly, this is a waterflooded reservoir. What was your water cut before and after air injection?

Response by Ron Miller

The initial water cuts were 94%. After the initiation of the combustion project, the WOR dropped significantly, and current water cut is about 84%.

Question from D. Yannimaras, Amoco Production Research, Tulsa, Oklahoma

What was your per-well production in the Capa Madison project?

Response by Al Erickson, Retired Koch Geologist

The per-well total fluid production shot up from about 60 bbl/D to 300 bbl/D after the initiation of the project.

Comment by Ron Miller

Al Erickson worked for Koch and is instrumental in launching Koch's combustion project. Last year he presented a paper on Koch's projects, entitled "An Appraisal of High Pressure Air Injection," in a Wyoming Geological Society meeting. You may find additional project information in that paper.

Question from A. Turta, Petroleum Recovery Institute, Calgary, Canada

How much ignition delay did you encounter in your projects?

Response by Ron Miller

The ignition is almost spontaneous, perhaps no more than four hours, I would say.

Question from A. Turta, Petroleum Recovery Institute, Calgary, Canada

What was your maximum air injection rate? What criteria did you use to arrive at this rate?

Response by Ron Miller

We try to inject at the maximum pressure, just below the frac pressure. This was necessary to maintain miscibility.

Question from an Unknown Person

How did you select your injectors?

Response by Ron Miller

We used the poor primary producers as injectors.

Question from Gordon Moore, University of Calgary, Canada

What is your air temperature at the injection wellhead?

Response by Ron Miller

Since we transported the air to the injectors through buried lines, the air temperature remained steady at about 52° F.

Question from an Unknown Person

Did you see any upgrade of your produced oil?

Response by Ron Miller

Since our oil is very light, we did not see much upgrading.

Question from an Unknown Person

Did you encounter any unusual operational problems in any of your projects?

Response by Ron Miller

None other than those I described in my presentation. Each project is unique and these problems are also unique. Nothing unusual, that cannot be solved.

APPENDIX
LIST OF SYMPOSIUM ATTENDEES

Allouard, Yves
Total Minatome Corporation
2 Houston Center, Suite 2000
Houston, TX 77210-4326
713-739-3000

Ames, Brian G.
Mobil Oil Canada
P.O. Box 800
Calgary, Alberta
Canada T2P 2J7
403-260-7641

Belgrave, John
University of Calgary
2500 University Drive NW
Calgary, Alberta
Canada T2N 1N4
403-220-7447

Bennion, Douglas
Hycal Energy
1338A-36 Ave. NE
Calgary, Alberta
Canada T2E 6T6
403-25-5800

Bolivar, Jesus
INTEVEP
Los Teques, Edo. Miranda
Apdo 76343
Caracas, Venezuela
58-2-908-6260

Brigham, Bill
Stanford University
Petroleum Eng. Dept.
Green Earth Sciences Bldg
Stanford, CA 94305-2220
415-723-0611

Buxton, Tom
Consultant
6747 S. 71 E. Ave.
Tulsa, OK 74133
918-492-1894

Carcoana, Aurel
North Dakota State Univ.
Eng. Science Dept.
Engineering Technology
Bldg, Rm. 209
Fargo, ND 58105
701-237-7105

Cathro, Doug
Canadian Liquid Air Ltd.
1050, 801 6th Ave. S.W.
Calgary, Alberta
Canada 1070A
403-262-6959

Chastang, Jean A.
TOTAL
Route de Versailles
Saint-Remy-Les-Chevreuse
France 78470
33-1-3085-7813

Coates, Roy
Alberta Research Council
P.O. Box 8330
Edmonton, Alberta
Canada T6H 5X2
403-472-4294

Compton, Al
Marathon Oil Company
P.O. Box 552
Midland, TX 79702
915-687-8266

De Holleben, Carlos Roberto
Petrobras
Rua Sacapan 807/201
Rio de Janeiro
Brazil 21910
55-21-280-0226

De Vries, A. S.
Shell Research BV
P.O. Box 60
AB Rijswijk
Netherlands 2280
070-311-2808

DiBona, Bennie
BDM-Oklahoma, Inc.
220 NW Virginia Ave.
Bartlesville, OK 74003
918-337-4200

Dillon, John
BP Exploration (Alaska)
P.O. Box 196612
900 E. Brenson Blvd.
Anchorage, Alaska
99519-6612
907-564-4648

Duncan, Grant
Petro-Canada
P.O. Box 2844
Calgary, Alberta
Canada T2P 3E3
403-296-4606

Ellison, Tim
Mobil Oil
13777 Midway Rd.
Dallas, TX 75244
214-851-8669

Ellwood, Dave
Marathon Oil Company
P.O. Box 552
Midland, TX 79702
915-687-8258

Erickson, Alexander
Petroleum Consultant
1870 S. Deer Park Circle
Grand Junction, CO 81503
303-241-6076

Farouq Ali, S.M.
University of Alberta
Petro Eng Dept
Edmonton, Alberta
Canada T5R 5P6
403-492-3453

Fassihi, Reza
Amoco Production
Research Co.
P.O. Box 3385
Tulsa, OK 74105
918-660-3963

Fraim, Mike
Phillips Petroleum Company
242 Geoscience Building
Bartlesville, OK 74004
918-661-5307

Freitag, Norman
Saskatchewan Research
Council
515 Henderson Drive
Regina, Saskatchewan
Canada S4N 5X1
306-787-9349

LIST OF SYMPOSIUM ATTENDEES—Continued

Gadelle, Claude
Institut Francais du Petrole
1 et 4 Av. du Bois Preau
Ryeil-Malmasso
France 92500
33-1-4752-6297

Geyelin, J.L.
Total Minatome Corporation
2 Houston Center, Suite 2000
Houston, TX 77210-4326
713-739-3000

Gillham, Travis
Amoco Production Company
P.O. Box 3092
Room 3.142
Houston, TX 77253
713-366-7771

Gunardson, Harold H.
Air Products and Chemicals
7201 Hamilton Blvd.
Allentown, PA 18195-1501
610-481-3196

Hall, Tom
Total Minatome Corporation
2 Houston Center, Suite 2000
Houston, TX 77210-4326
713-739-3000

Hamm, Ron
Shell Canada Limited
3655-36th St. NW
Calgary, Alberta
Canada T2L 1Y8
403-284-6619

Hardy, Carey
Consultant
1708 Wessex Circle
Richardson, TX 75082
214-235-5886

Hennings, Steve
Marathon Oil Company
1501 Stampede Ave.
Cody, WY 82414
307-587-4961

Holt, Richard
Mesquite Group
P.O. Box 1283
Fullerton, CA 92632
714-738-8224

Holyoak, Dale
Retired / Koch Exploration
409 North Westlink
Wichita, KS 67212
316-722-8271

Horton, Bob
Texaco
3901 Briarpark
Houston, TX 77042
713-954-6375

Jarrell Hal
Pyro Technology
10303 Northwest Freeway,
Suite 428
Houston, Texas 77092
713-680-8844

Jensen, Earl
Amoco Canada
6128 - 18th Ave N. E.
Calgary, Alberta
Canada T1Y 1P1
403-234-4041

Johnson, Frederick S.
Independent
P.O. Box 232
Casper, WY 82602
307-237-4741

Kenney, Pat
Kerr McGee
Leadership Square, Suite 700
Oklahoma City, OK 73125
405-270-6046

Kessler, Richard V.
Texaco Inc.
P.O. Box 509
Beacon, NY 12508
914-838-7647

King, Doug
Amoco Canada
#505 1001 - 14th Ave S. W.
Calgary, Alberta
Canada T2R 1L2
403-231-3822

Kirkpatrick, John
Consultant
Rt 3 Box 1310
Afton, OK 74331
918-257-5881

Koh, Chris
Mobil Oil Company
13777 Midway Rd.
Dallas, TX 75244
214-851-8144

Kumar, Vinodh
Koch Exploration
P.O. Box 2256
Wichita, KS 67201
316-832-5386

Machedon, Victor
Institute for Research &
Technology
29 Cultirii Blvd.
Prahova, Romania
40-44-33-4831

Mamora, Daulat D.
Texas A & M University
Petro Eng Dept
College Station, TX 77843
409-845-7842

Mehta, (Raj) S.A.
University of Calgary
2500 University Drive NW
Calgary, Alberta
Canada T2N 1N4
403-220-4804

Miller, Ronald J.
Koch Exploration Company
P.O. Box 2256
Wichita, KS 67201
316-832-5077

Moore, Gordon
University of Calgary
2500 University Drive NW
Calgary, Alberta
Canada T2N 1N4
403-220-7217

Moss, Jon
Consultant
1905 Hard Rock Rd.
Irving, TX 75061
214-986-0172

Murer, Anthony
Mobil Oil Company
10000 Ming Avenue
Bakersfield, CA 93311
805-665-4033

LIST OF SYMPOSIUM ATTENDEES—Continued

Olsen, David
BDM-Oklahoma, Inc.
220 NW Virginia Ave.
Bartlesville, OK 74003
918-337-4479

Ostapovich, Gene
Mobil Oil Canada
P.O. Box 800
Calgary, Alberta
Canada T2P 2J7
403-260-7353

Petri, Dan
Total Minatome Corporation
2 Houston Center, Suite 2000
Houston, TX 77210-4326
713-739-3000

Ramzel, Bruce
BDM-Oklahoma, Inc.
P.O. Box 2565
Bartlesville, OK 74005
918-337-4310

Reid, Tom
Department of Energy
Bartlesville Project Office
220 NW Virginia Avenue
Bartlesville, OK 74003
918-337-4233

Richardson, William C.
Texaco Inc./EPTD
P.O. Box 770070
Houston, TX 77215
713-954-6301

Roffers, John
Kerr-McGee Corp.
P.O. Box 25861
Oklahoma City, OK 73125
405-270-6015

Russell, G. W.
Russell Management Services
420 S. Main, Suite 1012
Tulsa, OK 74103
918-585-5691

Sarathi, Partha
BDM-Oklahoma, Inc.
220 NW Virginia Ave.
Bartlesville, OK 74003
918-337-4304

Slevinsky, Bruce
Petro-Canada
P.O. Box 2844
Calgary, Alberta
Canada T2P 3E3
403-296-4582

Stewart, Jim
Consultant
5619 Bolivia
Houston, TX 77091
713-682-0514

Strycker, Arden
BDM-Oklahoma, Inc.
220 NW Virginia Avenue
Bartlesville, OK 74003
918-337-4206

Tiffin, David
Amoco Production
Research Company
P.O. Box 3385
Tulsa, OK 74102
918-660-3728

Trent, Robert
University of Alaska
School of Mineral Engineering
Fairbanks, Alaska
99775-1190
907-474-7366

Turta, Alex
Petroleum Recovery Institute
3512 - 33rd St. N. W.
Calgary, Alberta
Canada T2L 2A6
403-282-1211

Ursenbach, Matt
University of Calgary
Dept. of Chem. & Pet.
Engineering
Calgary, Alberta
Canada T2N 1N4
403-290-2361

Vassoughi, Shapour
University of Kansas
4006 Lerned Hall
Dept. of Chem. &
Pet. Engineering
Lawrence, KS 66049-2223
913-864-4966

Villalba, Marlene
INTEVEP
Los Teques, Edo. Miranda
Apdo 76343
Caracas,
Venezuela 1070A
58-2-908-6260

Watts, Brad
Total Minatome Corporation
2 Houston Center, Suite 2000
Houston, TX 77210-4326
713-739-3000

Weissman, Jeffrey G.
Texaco Inc.
P.O. Box 509
Glenham, NY 12508
914-838-7654

Wheaton, Larry D.
Marathon Oil Company
P.O. Box 269
Littleton, CO 80160
303-347-5545

Wolter, Tom
Total Minatome Corporation
2 Houston Center, Suite 2000
Houston, TX 77210-4326
713-739-3000

Yannimaras, Demetrios
Amoco Production
Research Company
P.O. Box 3385
Tulsa, OK 74102
918-660-4148

Name withheld at request
Consultant

Name withheld at request
Investor

Name withheld at request
Consultant

☆U.S. GOVERNMENT PRINTING OFFICE: 1995 - 660-029/00060